BEFORE THE

SOUTH CAROLINA PUBLIC SERVICE COMMISSION

IN THE MATTER OF:	)	
APPLICATION OF SOUTH CAROLINA	)	
ELECTRIC AND GAS COMPANY FOR AN	)	**DOCKET NO. 2004-178-E**
INCREASE IN ITS ELECTRIC RATES	)	
AND CHARGES	)	

DIRECT TESTIMONY AND EXHIBIT

OF

GLENN A. WATKINS

ON BEHALF OF THE

SOUTH CAROLINA CONSUMER ADVOCATE

October 18, 2004

Technical Associates, Inc.

TABLE OF CONTENTS

PAGE

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PART I: INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glenn A. Watkins. My business address is James Center III, Suite 601, 1051 East Cary Street, Richmond, VA 23219.

Q. WHAT IS YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND?

A. I am Vice President and Senior Economist of Technical Associates, Inc., which is a business research and consulting firm with offices in Richmond, Virginia. Except during 1987 when employed by Old Dominion Electric Cooperative as its forecasting and rate economist, I have worked in varying capacities with Technical Associates continuously since 1980.

During my career at Technical Associates, I have conducted cost of capital, revenue requirement, load forecasting, cost of service, and rate design studies involving numerous electric, gas, water/wastewater, and telephone utilities, as well as presented expert testimony in Alabama, Arizona, Georgia, Maine, Maryland, Michigan, New Jersey, Illinois, Pennsylvania, Vermont, Virginia, South Carolina, and West Virginia in connection with these studies.

I hold an M.B.A. and B.S. in economics from Virginia Commonwealth University and I am a Certified Rate of Return Analyst. A more complete statement of my professional and educational background appears in the appendix to my testimony.

Q. HAVE YOU PREVIOUSLY APPEARED BEFORE THE SOUTH CAROLINA PUBLIC SERVICE COMMISSION?

A. Yes, I have provided expert testimony before this Commission on numerous occasions, including South Carolina Electric and Gas Company's (SCE&G or Company) last general rate case in 2002.

Q. PLEASE OUTLINE THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING.

A. Technical Associates has been engaged by the South Carolina Consumer Advocate (SCCA or CA) to conduct a cost of capital study of SCE&G's retail electric operations and to investigate the reasonableness of the Company's various ratemaking adjustments for revenue requirement purposes. The purpose of my testimony, therefore, is to present the results of my studies and offer recommendations regarding SCE&G's retail electric cost of capital and revenue requirement.

Q. ARE YOU PRESENTING AN EXHIBIT IN SUPPORT OF YOUR TESTIMONY?

A. Yes, my testimony includes one exhibit consisting of 22 schedules.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.

A. Based on my studies, I conclude that SCE&G's authorized retail electric base rate revenues should be decreased by $39.125 million. SCE&G's adjusted operating revenues at current rates are $1.480 billion and produce a rate of return on adjusted rate base of 8.44%. I have also concluded that SCE&G's overall cost of capital is 7.77% which is below that currently being earned by the Company. As such, a rate reduction totaling $39.125 million will generate income sufficient for SCE&G to earn a fair rate of return on the capital employed in providing retail electric service in South Carolina.

The following is my recommended capital structure, costs of debt and equity, and overall cost of capital:

Item	Percent	Cost	Weighted Cost
Long-Term Debt	46.89%	6.56%	3.08%
Short-Term Debt	3.78%	1.08%	0.04%
Preferred Stock	2.60%	6.40%	0.17%
Common Stock	46.73%	9.60%	4.49%
Total	100.00%		7.77%

I also recommend various operating income and rate base adjustments. These adjustments include:

Adjustment	SCE&G Adjustment Number [1/]
NCEMC Wholesale Revenues	1
Purchased Power Settlement Costs	2
Future Turbine Investment	5
Ammonia Costs	6
Payroll & Payroll Taxes	7
Healthcare Costs	8C
Future Transmission Costs	13C
Jasper Adjustments	17
Fossil Fuel Inventory	19
Grid South	20
Cash Working Capital	21
Interest Synchronization	22

PART II: COST OF CAPITAL

A. Economic/Legal Principles and Methodologies

Q. WHAT IS YOUR UNDERSTANDING OF THE ECONOMIC AND LEGAL PRINCIPLES WHICH UNDERLIE THE CONCEPT OF A FAIR RATE OF RETURN FOR A REGULATED UTILITY?

A. Rates for regulated public utilities are traditionally based on a revenue requirement/ rate of return on rate base concept. This revenue requirement establishes a level of operating expenses, taxes and depreciation deemed reasonable for rate setting purposes. In addition, the revenue requirement includes a provision for a fair and reasonable profit level to investors. This profit level is usually referred to as a fair rate of return, or cost of capital.

1/ See the Company's Application Exhibit D-II, page 3 for all adjustments proposed by SCE&G.

Because of the monopoly status of public utilities, and hence their ability to reap excessive profits absent proper regulation, the fair rate of return is considered to be the rate at which a utility can maintain its existing capital and attract new capital. Anything more is considered monopoly profits, and anything less is not sufficient compensation for the risks undertaken by investors.

From a legal standpoint, two U.S. Supreme Court decisions are universally cited as providing the legal standards for a fair rate of return. The first is Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

This decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942). In that decision, the court stated:

> The rate-making process under the (Natural Gas) Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and consumer interests . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of business. These include service on debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

This case affirmed the primary standards of the Bluefield case, as well as the public interest standard. The Hope case is also credited with the establishment of the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

It is apparent that these legal standards reflect the economic criteria encompassed in the "opportunity cost" principle of economics, which holds that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise on which regulation rests, namely that it is intended to act as a surrogate for competition.

B. **Capital Structure and Costs of Debt and Preferred Stock**

Q. PLEASE EXPLAIN WHAT A UTILITY'S CAPITAL STRUCTURE IS AND WHY IT IS IMPORTANT IN DETERMINING THE COST OF CAPITAL.

A. Capital structure refers to the types and percentages of various capital supplied by investors. There are two basic types of capital employed by utilities – debt and equity. Debt can be separated between short-term and long-term, and equity consists of preferred and common.

Financial theory tells us that each firm has an optimal capital structure such that its overall cost of capital is minimized. This is because debt capital (which is deductible for income tax purposes) is considered to have a lower cost than equity capital. However, as a firm's debt load increases, the firm's debt and equity costs will rise due to increased risk of default or not earning a reasonable level of equity return resulting from higher interest and debt repayment obligations.

Q. WHAT IS SCE&G'S CAPITAL STRUCTURE?

A. The following is SCE&G's capital structure as of June 30, 2004, as reported by the Company in response to Staff audit request No. 24, and CA Interrogatory No. 1-62:

	Amount (000)	Percent
Long-term Debt	$2,085,152	46.89%
Short-term Debt	$167,960	3.78%
Preferred Stock	$115,586	2.60%
Common Stock	$2,078,192	46.73%
Total	$4,446,890	100.00%

Q. DO YOU FIND THIS CAPITAL STRUCTURE TO BE PROPER FOR RATE MAKING PURPOSES?

A. Yes.

Q. IN ITS ORDER NO. 2003-38 IN SCE&G'S LAST RATE CASE, THE COMMISSION EXCLUDED SHORT-TERM DEBT FROM THE CAPITAL STRUCTURE. WHY HAVE YOU INCLUDED THIS DEBT IN THE COMPANY'S CAPITAL STRUCTURE IN THIS CASE?

A. Short-term debt is a source of inexpensive capital that SCE&G and other utilities employ to fund operations. This short-term debt is a definite source of funding to the Company, and to ignore it for ratemaking purposes provides a windfall to shareholders at the expense of customers rates.

Q. PLEASE COMMENT ON THE COMMISSION'S REASONS FOR EXCLUDING SHORT-TERM DEBT IN ORDER NO. 2003-38.

A. In its Order, the Commission provided the following explanation for excluding short-term debt from SCE&G's capital structure for ratemaking purposes:

> "The Commission, however, finds persuasive the testimony of Dr. Malkiel who testified that the rates and levels of short-term debt fluctuate significantly due to multiple, short-term factors, such as the impending maturities of long-term debt, and current levels of accounts receivables. Dr. Malkiel further testified that "[t]o include short-term debt [in cost of capital calculations] will tend to distort the company's true cost of financing its business operations since capital projects are financed through either equity or long-term debt." (Tr., Vol. III, Malkiel, at 832). The Commission finds that testimony to be reliable and probative and finds that the substantial evidence on the record support using long-term debt and equity as the basis for computing the Company's capital costs." [Order at 74-75]

With respect to Dr. Malkiel's 2002 testimony that short-term debt levels fluctuate significantly, my Schedule 1 provides a list of SCE&G's short-term debt outstanding each month since January 1999. Short-term debt levels can, and do, vary. Therefore, many regulatory commissions use the average balance concept for ratemaking, which is the same as that used for determining materials and supplies for rate base by this Commission. This makes perfectly good sense because short-term debt is generally used to fund fuel and other supply inventories as well as provide cash working capital which also can fluctuate significantly. As contained in my Schedule 1, the following are SCE&G's average short-term debt balances for the test-year and twelve months prior to the test year:

Test Year (4/03-3/04)	$173,933,000
1 Year Prior (4/02 - 3/03)	$181,224,417

I have used the actual balance outstanding as of June 30, 2004 ($167,960,000) in my analysis, but would not be opposed to using an average test-year amount.

With respect to Dr. Malkiel's 2002 testimony that "to include short-term debt in cost of capital calculations will tend to distort to Company's true cost of financing its business operations since capital projects are financed through either equity or long-term debt", this illustrates his apparent misunderstanding of the costs included in utility ratemaking. SCE&G's per books (total electric) rate base at the end of the test year is reported to be $4,014,886,000. This amount includes $125,178,000 in materials and supplies, $83,777,000 in cash working capital, and $14,569,000 in prepaid expenses.[2] These amounts are all capitalized and are included in the Company's rate base for ratemaking purposes and short-term debt is considered to be the primary source of funding for these rate base items. I suppose one could price these working capital items at short-term interest rate costs and then assign all plant and long-term items based on long-term debt and common equity cost rates, but typically it is preferred not to pigeon hole specific items with specific costs.

In summary, the Company enjoys inexpensive short-term debt financing, and to ignore this fact is to overstate the rates paid by SCE&G's customers. Should the Commission reject the consideration of short-term debt costs, it should also reject the inclusion of short-term assets from rate base.

[2] Per SCE&G application, Exhibits D-II through D-VI.

Q. WHAT IS SCE&G'S COST OF SHORT-TERM DEBT?

A. In CA Interrogatory No. 1-63, I asked the Company to provide its current short-term debt interest rate. The Company stated in its response that the daily average interest rate for SCE&G's commercial paper[3/] for the first quarter of 2004 was 1.0823%. This rate does not include backup credit facility fees assessed by banks nor the administrative charges for establishing credit lines.

This is the most recent short-term interest rate available, and I have assumed that the fees and charges referenced above that actually were incurred during test year were booked to expenses and are already included in cost of service. However, if these fees and charges were actually incurred and not otherwise included in SCE&G's cost of service, they should be reflected in the Company's cost of service. Moreover, consistent with my other cost of capital recommendations, if short-term debt costs have changed significantly since the first quarter of 2004, it is appropriate to update these values as well.

Q. WHAT IS SCE&G'S COST OF LONG-TERM DEBT?

A. The Company's filing indicates its embedded cost of long-term debt is 6.56%. I reviewed the details underlying this amount and concur with the Company.

3/ Commercial paper is the major instrument of short-term debt.

Q. WHAT IS SCE&G'S COST OF PREFERRED STOCK?

A. SCE&G's filing indicates a cost rate of 6.40%. As with long-term debt, I also reviewed the details underlying the Company's preferred stock cost calculations and concur with this value.

C. <u>Cost of Common Equity</u>

Q. HOW CAN THE COST OF COMMON EQUITY FOR A UTILITY BE ESTIMATED?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of common equity. This is the case since the cost of equity is an opportunity cost and is prospective, or forward looking, which indicates it must be estimated.

There are several useful models which can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. In performing analyses of the cost of common equity, it is customary and appropriate to consider the results of more than one method. The analyst and/or Commission must then decide upon the appropriate weight to give the results of each method in the determination of the cost of common equity. This follows, since each method requires judgment as to the reasonableness of its assumptions and inputs; each model has its own way of examining investor behavior; each model proceeds from different fundamental premises, most of which cannot be validated empirically; and each model may not at all times be representative of current investor behavior. Just as there is no uniformity as to which method is used by investors, there should not be a single method exclusively used to estimate a utility's cost of common equity. At the very least, alternative methods should be used as a check on a primary or preferred method.

Q. WHICH METHODS HAVE YOU EMPLOYED IN YOUR ANALYSES OF SCE&G'S COST OF COMMON EQUITY?

A. I have employed Discounted Cash Flow (DCF) and the Capital Asset Pricing Model (CAPM). However, I am aware that this Commission has not favored the CAPM, and shown a preference for DCF analyses.

Q. PLEASE EXPLAIN YOUR STATEMENT THAT THE COMMISSION HAS NOT FAVORED THE CAPM AND HAS SHOWN A PREFERENCE FOR DCF ANALYSES.

A. In Order No. 2003-38 (SCE&G's last rate case), the Commission stated:

> The Commission also finds credible the testimony of Dr. Malkiel that the empirical evidence and research raises questions concerning the theoretical assumptions underlying the CAPM model (*Id.* at 839-41). The CAPM model employs a measure of a stock's volatility relative to the broader market, called beta. On the basis of the beta, the

> CAPM model attempts to calculate the company's risk and market's required return for taking on that risk. The validity of beta as an indicator of required return is at the heart of the CAPM model. (*Id.* at 839). Recent research, however, has shown that betas are not stable, and they cannot be accurately measured. (*Id.* at 815). More importantly, a number of recent and important studies in the finance literature have shown that beta and return are essentially uncorrelated. (*Id.* at 815-17, 839-41; Vol. IV, Malkiel at 917-18) (Order at 56).

Q. THE COMMISSION ALSO STATED IN ORDER NO. 2003-38 THAT ITS DECISION WAS BASED ON THE RECORD BEFORE IT IN THAT PROCEEDING, AND THAT IT WILL NOT FORECLOSE PARTIES FROM ADVANCING TESTIMONY USING CAPM IN FUTURE CASES. WHY DO YOU THEN CONCLUDE THAT THIS COMMISSION DOES NOT FAVOR CAPM?

A. There are two interrelated reasons. First, this Commission found Dr. Malkiel's 2002 testimony regarding his disdain for the CAPM persuasive in the last case. Dr. Malkiel is the Company's cost of equity witness in the current case, and presumably his views of CAPM have not changed in two years.

Second, and more important, is the Commission's finding that it has concerns over the theoretical validity of the CAPM. The theory and assumptions underlying the CAPM have not changed since that Order was published.

Q. GIVEN YOUR PREFERENCE TO RELY ON MORE THAN ONE METHOD AND THE COMMISSION'S APPARENT PREFERENCE FOR DCF ANALYSIS, HOW DID YOU PROCEED?

A. I have conducted my cost of equity and cost of capital studies on two bases. The first is my preferred approach which employs DCF and CAPM for determining SCE&G's cost of equity. As previously discussed, I also include short-term debt in the capital structure under my preferred approach. The second approach employs only DCF and uses the Commission's preference to consider only forecasted earnings per share in determining the DCF growth rate. I also excluded short-term debt in the capital structure under my alternative recommendation.

1. <u>Selection of Comparison Groups</u>

Q. HOW HAVE YOU ESTIMATED THE COST OF COMMON EQUITY FOR SCE&G?

A. In addition to applying the DCF and CAPM methods specifically to SCE&G's parent, SCANA, it is useful to also analyze groups of comparison or "proxy" companies as a substitute for SCANA to determine its cost of common equity. The most frequently used method is to select a group of comparison companies. I have examined the proxy or "peer" group selected by Company witness Osborne. Although I believe Mr. Osborne's group of comparable companies may be somewhat small in number, I find this group overall to reasonably reflect the risks and business profile of SCANA and its largest subsidiary SCE&G. Therefore, I have accepted his peer group of companies.

2. <u>Discounted Cash Flow Analysis</u>

Q. WHAT IS THE THEORY AND METHODOLOGICAL BASIS OF THE DISCOUNTED CASH FLOW MODEL?

A. The discounted cash flow (DCF) model is perhaps the most commonly-used model for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows. When applied to common stocks, the dividend discount model describes the value of a stock as follows:

$$P = \frac{D_1}{(1+K_1)} + \frac{D_2}{(1+K_2)^2} + \ldots + \frac{D_n}{(1+K_n)^n} = \sum_{i=1}^{n} \frac{D}{(1+K)^n}$$

where: P = current price

D_1 = dividends paid in period 1, etc.

K_1 = discount rate in period 1, etc.

n = infinity

This relationship can be simplified if dividends are assumed to grow at a constant rate of “g”. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, the price of a stock is determined as follows:

$$P = \frac{D}{(K - g)}$$

where: P = current price

D = current dividend rate

K = discount rate (cost of common equity)

g = constant rate of expected growth

This equation can be solved for K (i.e., the cost of common equity) to yield the following formula:

$$K = \frac{D}{P} + g$$

This formula essentially states that the return expected or required by investors is comprised of two factors: the yield (current income) and expected growth (future income).

Q. PLEASE EXPLAIN HOW YOU HAVE EMPLOYED THE DCF MODEL.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for the group of utility stocks described previously with several indicators of expected growth. Moreover, I will present my preferred approach to estimating growth (g) as well as this Commission's stated preferred approach.

Q. HOW DID YOU DERIVE THE DIVIDEND YIELD COMPONENT OF THE DCF EQUATION?

A. There are several methods which can be used for calculating the yield component. These methods generally differ in the manner in which the dividend rate is employed, i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate yield component is a quarterly compounding variant which is expressed as follows:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This yield component recognizes the timing of dividend payments as well as dividend increases.

The P_o in my yield calculation is the average (of high and low) stock price for each company for the most recent three month period (June-August, 2004). The D_o is the current annualized dividend rate for each company.

However, I note that there are other variations to calculate the yield component. For example, Dr. Malkiel has used the formula of:

$$Yield = \frac{D_0(1+g)}{P_0}$$

The difference in our two methods rests on the assumption of when the next cash dividend change will occur. Dr. Malkiel's approach assumes that annual dividend growth has just occurred and the dividend growth will not occur again for the entire first year. My approach assumes that the next annual dividend increase will occur in six months; i.e., half way into the yearly dividend growth period.[4/]

The impact on virtually every DCF result (mine and Dr. Malkiel's) is that my method produces about a 10 basis point lower DCF than the yield variation used by Dr. Malkiel. In my opinion, this difference is immaterial given the other cost of equity issues in this case.

Q. HOW HAVE YOU ESTIMATED THE GROWTH COMPONENT OF THE DCF EQUATION?

A. The growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the growth component is to reflect the growth expected by investors which is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. A wide array of techniques exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of growth in deriving the growth component of the DCF model.

4/ For example, assume the current dividend (D_0) is $2.00 and there is a 4% annual growth rate. Dr. Malkiel's approach assumes that the dividend was increased today from $1.92 ($2.00/1.04), and will increase again one year from now to $2.08 ($D_1$). My approach assumes that the current dividend of $2.00 was last increased six months ago and that the next change will occur six months from the present, to become $2.04 in 6 months. Hence, the dividend 1 year from now will be $2.04 and half way through the annual growth period.

I have considered, but not necessarily employed, five indicators of growth in my DCF analyses. These are:

1. Historical (5-year average) earnings retention, or fundamental growth;
2. 5-year average historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS);
3. projected earnings retention growth;
4. projections of EPS, DPS, and BVPS; and
5. 5-year projections of EPS growth as reported by Thomson First Call (formerly I/B/E/S).

I believe this combination of growth indicators is a representative and appropriate set with which to estimate investor expectations of growth for SCANA and the group of comparison companies.

Q. PLEASE DESCRIBE YOUR VARIOUS DCF CALCULATIONS.

A. Schedule 2 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield. Pages 2-3 show the growth rates for the groups of comparison companies. Page 4 shows my recommended DCF approaches and calculations using recent historical growth rates and forecasted growth rates.

Q. PLEASE EXPLAIN WHY A THREE-MONTH AVERAGE STOCK PRICE IS APPROPRIATE FOR DETERMINING A COMPANY'S COST OF EQUITY.

A. Even though the stock market may be efficient over time, significant day to day variations can and do occur in the market. Because the DCF method is a market determined approach to estimate the cost of equity, a proper market price must be used. In my opinion, a recent 3-month average stock price smooths day to day random oscillations in stock prices.

Q. YOUR RECOMMENDED ANALYSIS SHOWN ON PAGE 4 OF YOUR SCHEDULE 2 IS COMPRISED OF DCF RATES CALCULATED ON BOTH HISTORICAL AND PROSPECTIVE GROWTH RATES. IN SCE&G'S LAST RATE CASE, THIS COMMISSION FOUND A PREFERENCE FOR USING ONLY FORECASTED OR PROSPECTIVE GROWTH RATES. PLEASE EXPLAIN WHY YOU CONSIDERED BOTH HISTORIC AND PROSPECTIVE GROWTH WITHIN YOUR DCF ANALYSIS.

A. I will discuss considerations to specific historic growth rates momentarily. From a general perspective, the consideration of growth is, of course, forward looking. In this regard, investors will use a variety of methods to forecast expected growth. Dr. Malkiel has stated that "calculations of past earnings growth are no help in predicting future growth." With respect to certain companies and certain industries, I agree wholeheartedly with Dr. Malkiel. For example, the invention or introduction of a new product can greatly influence a firm's future growth vis-a-vis its historical performance.

However, such is generally not the case with fixed regulated utilities.[5/] The products, services, and customer mix of utilities are well established and they tend to have reasonably stable and reliable growth in regulated markets. Thus, most utility analysts agree that, in general, historical growth is a reasonable barometer of future growth. This, of course, is not without exception, and as with forecasted growth rates, should be considered on a case by case basis, and evaluated carefully.

This brings me to my consideration and use of specific growth rates for DCF purposes. As shown on pages 2 and 3 of Schedule 2, I considered historic retention rate, EPS, DPS, and BVPS (book value per share) growth rates for the comparison group and for SCANA. However, as shown on page 4 of Schedule 2, I excluded historic DPS and BVPS growth in my ultimate analysis. Historical DPS growth was excluded in this study due to the recent dividend reductions of Wisconsin Energy and SCANA. I excluded BVPS (both historic and prospective) growth due to this Commission's stated reasons in SCE&G's last rate case for not considering this growth measure.[6/] Therefore, as shown on page 4 of Schedule 2, my selected historic growth rate incorporates the average retention growth and EPS growth.

Q. PLEASE EXPLAIN YOUR DCF ANALYSIS EMPLOYING FORECASTED OR PROSPECTIVE GROWTH RATES.

5/ Fixed utilities are generally considered electric, natural gas, water, and wastewater utilities.

6/ Order No. 2003-38 at 64.

A. As shown on page 4 of Schedule 2, my prospective analysis includes Value Line forecasted retention growth, EPS and DPS (average) and IBES/First Call growth rates.

Q. PLEASE SUMMARIZE YOUR DCF FINDINGS.

A. The following is a summary of my DCF findings from page 4 of Schedule 2:

	DCF Cost of Equity	
	Historic Growth	Prospective Growth
Comparison Group:		
Average	8.9%	8.8%
Median	9.4%	8.7%
SCANA	7.7%	9.1%

Q. WHAT IS YOUR CONCLUSION CONCERNING THE DCF COST OF EQUITY FOR SCE&G?

A. I find a reasonable DCF cost of equity for SCE&G's retail electric operations to be in the range of 8.7% to 9.4%. Based on the mid-point of this range (9.1%) and the clustering of various DCF results around 9.1%, I conclude that a DCF cost of 9.1% is appropriate for SCE&G.

3. Capital Asset Pricing Model Analysis

Q. PLEASE DESCRIBE THE THEORY AND METHODOLOGICAL BASIS OF THE CAPITAL ASSET PRICING MODEL.

A. The Capital Asset Pricing Model (CAPM) is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and the market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory which studies the relationships among risk diversification and expected returns.

Q. HOW IS THE CAPM DERIVED?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

$R_m - R_f$ = market risk premium

Q. PLEASE EXPLAIN WHAT THE TERM BETA REPRESENTS.

A. Beta is an indicator of investment risk as it is a measure of the expected amount of change in a security's (common stock's) return that results from a change in general security market returns. As such, beta indicates the security's variability of return relative to the return variability of the overall market.

Variability of market returns is a measure of risk and is caused by two general factors. First, changes in economic, social, and political conditions affect the risk structure and market prices of all securities. Changes in these factors consequently cause the market return to vary. This is referred to as systematic or non-diversifiable risk. Second, each company and industry has unique business and financial attributes which also cause returns and prices to vary. This is known as non-systematic or diversifiable risk.

Investors can, through diversification of their security holdings, substantially reduce or eliminate the return variation caused by the second general factor (i.e., the non-systematic or diversifiable risk). However, the return variance or risk caused by the first factor (i.e., the systematic or non-diversifiable risk) cannot be eliminated because changes in these factors impact all securities to some degree.

Beta, the indicator of a security's investment risk, serves as a measure by which the security's market return requirements can be identified. Securities with high betas require relatively higher returns because these securities exhibit a greater volatility than do securities with relatively lower market betas.

Each security's market required rate of return is proportional to its respective beta. The additional return (above the overall market return) required by a high beta security (greater than one) is a return premium required to attract capital. The return premium is required because of the higher level of market risk embodied in that security. Hence, the premium is generally referred to as a risk premium. The opposite is true for securities with a beta less than one.

The CAPM, by identifying the specific relationship between non-diversifiable or systematic risk and its associated risk premium requirements, can be used to determine the required rate of return on equity.

Q. WHAT GROUPS OF COMPANIES HAVE YOU UTILIZED TO PERFORM YOUR CAPM ANALYSES?

A. I have performed CAPM analyses for the same group of companies evaluated in my DCF analyses.

Q. WHAT RATE DID YOU USE FOR THE RISK-FREE RATE?

A. The first term of the CAPM is the risk free rate (R_f). The risk-free rate reflects the level of return which can be achieved without accepting any risk.

In reality, there is no such thing as a truly riskless asset. In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. This follows since

Treasury securities are default-free owing to the government's ability to print money and/or raise taxes to pay its debts.

Two types of Treasury securities are often utilized as the R_f component: short-term U.S. Treasury bills and long-term U.S. Treasury bonds. I have performed CAPM calculations using the three month average yield (June-August, 2004) for 20 year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 5.25 percent.

Q. WHAT BETAS DID YOU EMPLOY IN YOUR CAPM?

A. I utilized the most current Value Line betas for each company in the comparison group. These are shown on Schedule 3 and are seen to be within a range of 0.70 to 0.80 (the beta for the entire market is 1.00).

Q. HOW DID YOU ESTIMATE THE MARKET RISK PREMIUM?

A. I did not use individual values of R_m and R_f to calculate the risk premium, but rather, used the historic risk premium from Ibbotson & Associates. I have developed such a market risk premium by comparing the 1926-2003 total returns for:

Large Company Stocks	12.4%
Long-term Government Bonds	5.8%
Risk Premium	6.6%

Schedule 3 shows my CAPM calculations using this risk premium. The results are:

Comparison Group	
Average	10.2%
Median	10.2%
SCANA	9.9%

These indicate CAPM cost rates of 9.9 percent to 10.2 percent.

Q. WHAT IS YOUR CONCLUSION CONCERNING THE CAPM COST OF EQUITY FOR SCE&G?

A. My CAPM results indicate a cost of 9.9 percent to 10.2 percent. I conclude that the appropriate midpoint of 10.1% is an appropriate CAPM cost.

Q. BASED ON YOUR PREFERRED APPROACH OF CONSIDERING DCF AND CAPM, WHAT IS YOUR RECOMMENDED COST OF COMMON EQUITY FOR SCE&G IN THIS PROCEEDING?

A. I find a reasonable cost of equity for SCE&G's retail electric operations to be in the range of 9.1% to 10.1%. My recommended cost of equity (allowed rate of return on common equity) in this case is the mid-point of this range or 9.6%.

4. Alternative Cost of Equity Analysis

Q. YOU STATED EARLIER THAT IN SCE&G'S LAST CASE, THE COMMISSION STATED A PREFERENCE FOR RELYING ON DCF WHEREBY THE DCF COST OF EQUITY WAS DETERMINED USING ONLY FORECASTED EARNINGS GROWTH RATES. HAVE YOU CONDUCTED SUCH AN ANALYSIS FOR PURPOSES OF THIS CASE?

A. Yes.

Q. PLEASE DISCUSS YOUR ALTERNATIVE COST OF EQUITY ANALYSIS.

A. The analysis shown on Schedule 4 is an alternative DCF analysis based on the Commission's preferred approach in SCE&G's last case of using only projected EPS growth rates. As such, the analysis in Schedule 4 considers the EPS growth estimates published by Value Line and Thomson First Call. I present DCF rates based on my preferred adjusted yield method (1 + .5G) as well as the method used by Dr. Malkiel (1 + G). The results are as follows:

	DCF	
	(1 + .5G) Adjusted Yield Method	(1 + G) Adjusted Yield Method
Comparison Group:		
Average	9.0%	9.1%
Median	8.6%	8.7%
SCANA	9.1%	9.2%

Based on this alternative analysis, I conclude that a reasonable cost of equity range is 8.6% to 9.2%, which is marginally lower than my recommended DCF range of 8.7% to 9.4% range.

D. Total Cost of Capital

Q. BASED ON YOUR RECOMMENDED CAPITAL STRUCTURE AND COST OF EQUITY, WHAT IS YOUR RECOMMENDED OVERALL COST OF CAPITAL TO SCE&G IN THIS RATE CASE?

A. The following is my recommended overall cost of capital for this case. These amounts are also provided in my Schedule 5.

Item	Pct	Cost	Weighted Cost
L-T Debt	46.89%	6.56%	3.08%
S-T Debt	3.78%	1.08%	0.04%
Preff. Stock	2.60%	6.40%	0.17%
Comm. Stock	46.73%	9.60%	4.49%
Total	100.00%	----	7.77%

Q. SHOULD THE COMMISSION REJECT THE INCLUSION OF SHORT-TERM DEBT IN THE CAPITAL STRUCTURE AND RELY SOLELY ON ITS PREFERRED DCF APPROACH FROM THE LAST CASE, WHAT IS YOUR ALTERNATIVE COST OF CAPITAL?

A. The following cost of capital is recommended under those circumstances. These amounts are provided in my Schedule 6.

Item	Amt	Pct	Cost	Weighted Cost
L-T Debt	$2,085,152	48.73%	6.56%	3.20%
Preff. Stock	115,586	2.70%	6.40%	0.17%
Comm. Stock	2,078,192	48.57%	9.10%	4.42%
Total	$4,278,930	100.00%		7.79%

E. <u>Flotation Costs</u>

Q. IS SCE&G REQUESTING A FLOTATION COST ADJUSTMENT IN THIS CASE?

A. Yes. Dr. Malkiel notes on page 19 of his direct testimony that his cost of equity estimate (10.5%) includes flotation costs of 4.25%.[7/] However, in response to CA Interrogatory No. 2-3, he indicates that his recommendation is to multiply the DCF cost of equity by 104.44% to properly reflect floatation costs. In his testimony on page 21, Dr. Malkiel testifies that the transaction costs involved in raising equity and debt capital both in the past and in the future can only be recovered if the Commission allows the Company to earn each year an additional rate of return reflecting those costs. Furthermore, as stated on page 29 of his testimony, Dr. Malkiel's recommended ROE of 11.48% includes consideration of flotation costs to raise capital.

[7/] Dr. Malkiel did not explain or present evidence on how he determined his 4.25% flotation costs. Response to CA Interrogatory No. 2-2(C) indicates that 4.25% is based on the testimony of Kevin Marsh in Docket No. 2002-223-E.

Q. DOES SCANA HAVE ANY PLANS TO RAISE NEW EQUITY CAPITAL THROUGH A PUBLIC OFFERING IN THE FORESEEABLE FUTURE?

A. No, in response to Staff Data Request No. 1-8, SCE&G indicates that no public offerings of common stock are planned during the next few years.

Q. WHEN WAS SCANA'S MOST RECENT SIGNIFICANT COMMON STOCK PUBLIC OFFERING?

A. October 2002.[8/]

Q. DID THIS COMMISSION GRANT A FLOTATION COST ADJUSTMENT IN SCE&G'S LAST ELECTRIC RATE CASE (DOCKET NO. 2002-223-E) ASSOCIATED WITH THE ABOVE REFERENCED OFFERING AND SALE?

A. Yes. As a result of new stock that was issued in October 2002, a 20 basis point add-on to the allowed ROE was granted in that case.

Q. WHAT WERE THE COMMISSION'S REASONS FOR ALLOWING A FLOTATION ADJUSTMENT IN THE SCE&G'S LAST RATE CASE?

[8/] Per response to Staff 1Data Request No. 1-9.

A. In its Order No. 2003-38, the Commission stated that it has been the practice in past cases to allow applicants to recover a flotation adjustment where a flotation of new equity has taken place in the recent past or is planned during the next three years (Order at 71). In addition, the Commission opined that there is an on-going nature of flotation costs, and stated in its Order: "they [flotation costs] represent a difference in the amount of funds that investors have invested in the Company compared to the amount the Company actually receives" (Order at 72).

Q. IN THAT ORDER, THE COMMISSION FOUND THAT EXISTING STOCKHOLDERS ARE PENALIZED WHEN NEW COMMON STOCK IS ISSUED, AND THAT WHEN NEW STOCK IS ISSUED, THE STOCK PRICE DECREASES AND EARNINGS PER SHARE DECREASE. DO YOU AGREE?

A. No.

Q. PLEASE EXPLAIN.

A. In theory, the issuance of new shares of common stock will dilute earnings if there are no other offsetting factors. However, this is true if, and only if, the incremental new capital raised does not provide a return at or above the earnings received on the older capital. Under traditional utility ratemaking (as is employed in S.C.), all capital (rate base) is allowed the same rate of return. Thus, this additional capital is used to finance additions to rate base, and all rate base (new and old) is authorized the same rate of return. This ratemaking allowance prevents dilution in earnings since the new investment is granted the same rate of return as the older investments in capital. Moreover, at least for a regulated utility, the funds raised (per share) must be compared to the book value per share in order to determine if any dilution in book value per share occurred. This is important because rate base and allowed profits are based on actual book values. As a factual matter, the October 2002 sale of stock resulted in a premium and instant addition to current stockholder values as shown by the following facts:

New Shares [9/]			
(1) Book Value Per Share	(2) Number of Shares	(3) Gross Price Per Share	(4) Net Price Per Share
$20.84	6,000,000	$25.10	$24.25

As indicated, the new issuance generated additional wealth to current investors over and above the equal rate of earnings this new capital will generate of $20.46 million [6,000,000 x ($24.25 - $20.84)]. This is a simple matter of arithmetic and is because the new offering sold at a premium of 16% over book value ($24.25 ÷ $20.84). Therefore, because the regulatory process allows the Company to earn the same level of return on new capital as older capital, shareholders were made better off as a result of the premium on the sale of new shares there. Thus, an add-on was incorrect to "ensure that the return investors actually receive for the funds invested in the Company equals the return that the Commission establishes with reference to the Company's rate base" (Order at 72).

9/ Per SCE&G response to Staff Data Request No. 1-9.

Q. IN ITS ORDER NO. 2003-38 ON PAGE 73, THE COMMISSION STATED THAT IT ADOPTED ITS PREFERRED FLOTATION COST METHOD, AT LEAST IN PART, BECAUSE THIS METHODOLOGY MEASURES THE ACTUAL MARKET REACTION TO THE STOCK ISSUANCE. WHAT WAS THE ACTUAL MARKET REACTION TO THIS STOCK ISSUANCE?

A. The Commission found that the stock price would decrease as a result of the dilutive effects of the new offering. As I explained earlier, this is only correct if all other factors are not considered. I examined SCANA's stock performance before and after the stock issuance and compared SCANA's stock performance during this period to the S&P 500 index. The daily closing stock prices for SCANA, the S&P 500, and the Utility Index[10] from September 17, 2002 through December 18, 2002 are provided in my Schedule 7. As this schedule clearly shows, SCANA's stock price steadily increased during this entire period, from about $25.50 to about $30.75 per share. This represents an increase of about 8%. At the same time, the S&P 500 increased by about 6% (from about $850 to about $900) and the utility index increased only about 2% (from about $250 to about $256). As such, there is no factual evidence supporting the notion that the stock issuance had a negative impact on SCANA's stock price. In fact, the reduced leverage ratio of SCANA after the issuance had a positive influence on the stock's price.

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[10] The Utility Index (Yahoo Finance Symbol ^UTY) is comprised of the following public utility stocks: AEE, AEP, AES, LNP, D, DTE, DUK, ED, EIX, ETR, EXC, FE, FPL, NU, PCG, PEG, PGN, SO, TXU, and XEL.

Q. EVEN THOUGH THE NEW ISSUANCE GENERATED A PREMIUM WELL OVER THE BOOK VALUE OF SCANA'S STOCK, WHAT WERE THE ISSUANCE COSTS ASSOCIATED WITH THAT OFFERING?

A. The issuance costs were $5.1 million.[11/]

Q. HOW WERE THESE $5.1 MILLION REFLECTED ON SCANA'S BALANCE SHEET?

A. Only the net proceeds of the equity sale show up on the balance sheet. Therefore, the $5.1 million itself does not appear, per se.

Q. CAN YOU PROVIDE AN EXAMPLE SHOWING HOW THE NEW ISSUANCE EFFECTED SCANA'S BALANCE SHEET AND VALUES PER SHARE?

A. Yes. Based on the example provided in Dr. Malkiel's testimony on pages 8 and 9 in this case,, suppose a company has a balance of $1,000 and 100 shares outstanding (Book value = $10/share). Suppose the company desires to raise additional equity capital and issues a stock offering of an additional 100 shares priced at $12.04 (M/B ratio of 120.44% which is the same as the actual SCANA 2002 offering). This offering would generate gross proceeds of $1,204, but after issuance costs of 3.4% (the same as SCANA's 2002 offering),

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[11/] 6,000,000 shares times ($25.10-$24.25).

thet amount of $1,163 [$1,204 x (1-3.4%)] is reflected as the net gain to the balance sheet. The balance sheet total equity becomes $2,163 with 200 shares outstanding or $10.82 new book value per share. As can bee seen, there was a gain in the book value of the stock.

Q. GIVEN THE COMMISSION'S APPROVAL OF A 20 BASIS POINT ADD ON TO THE APPROVED RETURN ON EQUITY IN SCE&G'S LAST RATE CASE, HOW MUCH EQUITY HAS BEEN ADDED TO SCANA'S BALANCE SHEET AS A RESULT OF THAT ACTION?

A. The additional after-tax income, and therefore, additional equity generated from this 20 basis points has added about $6.6 million to the equity in SCANA's balance sheet.

The Commission's Order in the 2002 case became effective on February 1, 2003. Assuming that current rates will remain effective until about February 1, 2005 (when this case concludes), this is two years. The annual additional income and increase to SCANA's retained earnings has been $3.3 million.[12/] As a note, the additional income has amounted to $6.6 million. However, due to income taxes, the 20% add-on has cost ratepayers an additional $11.0 million.

12/ Approved rate base was $3,174,083,000. The approved common equity ratio was 52.18%. Therefore, $3.174 billion x 0.002 x .5218 = $3.312 million.

Q. THE ADDITIONS TO THE EQUITY IN SCANA'S BALANCE SHEET HAVE BEEN $6.6 MILLION AS A RESULT OF THE LAST FLOTATION ADD-ON, WHILE THE FLOTATION COST WAS $5.1 MILLION IS THAT CORRECT?

A. No. Because the new issuance was sold at a premium over book value, and there was not dilution in the book or market value of SCANA's stock after the issuance, there were no true market or book flotation costs associated with that sale, and there never will be.

However, you are correct that the Commission approved add-on has generated an additional $6.6 million in equity to SCANA's balance sheet and the issuance costs were $5.1 million. I believe it is important to note this funding has come entirely from SCANA's South Carolina retail electric ratepayers. SCANA's natural gas and unregulated customers did not share at all in this additional equity pumped into SCANA.

Q. DO YOU HAVE ANY OTHER COMMENTS ON FLOTATION COSTS FOR RATEMAKING PURPOSES?

A. Yes. The Commission relied exclusively on DCF analysis in establishing the authorized ROE (before the add-on) in SCE&G's last rate case. As a result of the arithmetic of the DCF model, any flotation costs (real or unreal) were already reflected in the DCF cost results prior to the 2002 rate decision , i.e., any flotation costs were already reflected in the cost of equity awarded in the 2002 case.

Q. PLEASE EXPLAIN.

A. The DCF takes the form of:

$$K = \frac{D}{P} + G$$

The costs and benefits of new issuances are captured automatically by the market in the stock price (P). In other words, under the hypothesis that the new issuance will reduce the price of the stock, the cost of equity is higher because the price is lower as a result of the stock issuance. Therefore, DCF directly captures any costs or benefits of a new stock issuance.

F. <u>Other Comments on Dr. Burton Malkiel's Testimony</u>

Q. WHAT ARE YOUR CONCERNS REGARDING DR. MALKIEL'S DCF ANALYSIS?

A. For reasons I have already discussed, I do not think it is appropriate to calculate DCF cost of equity based on a single day's closing stock prices. I also believe it is shortsighted to rely on a single source or single growth estimate in evaluating a utility's cost of equity for ratemaking purposes. Finally, I believe that SCANA's DCF cost should definitely be considered in this ratemaking process.

On page 20 of his direct testimony, Dr. Malkiel presents a DCF analysis of large utility holding companies and three large telecommunications companies. Because these larger companies produce a lower DCF cost of equity, Dr. Malkiel concludes, a priori, that these companies are less risky than the Osbourne sample of companies, and hence, less risky than SCE&G's retail electric operations. Each of the utility companies in Dr. Malkiel's large company group are involved in significant levels of unregulated business enterprises. Each of the three telecommunications companies are engaged in significant levels of unregulated cellular wireless, internet services, and fiber optics operations. These unregulated business activities are clearly more risky than SCE&G's traditionally regulated retail electric operations, and Mr. Malkiel may or may not have considered this fact. Had Dr. Malkiel applied his own DCF analysis to SCANA, he would have found that SCANA's DCF cost is lower than his "large" group of companies.

Dr. Malkiel also cites the fact that small company stock returns have historically been higher than large company stocks, as reported by Ibbotson & Associates. In this regard, there is no disputing these facts. However, Dr. Malkiel fails to mention the fact that the "small" company group in the Ibbotson Annual report is comprised solely of the DFA Micro Cap Fund. This mutual fund is made up of companies with a median market capitalization of $212 million and invests only in the smallest 20% of all stocks. This compares to the Osbourne group with market capitalizations ranging from $1.718 billion to $3.813 billion. Moreover, SCANA's market capitalization exceeds $4 billion.

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING DR. MALKIEL'S DIRECT TESTIMONY?

A. Yes. I have also explained why a flotation cost adjustment is inappropriate in this case, and when incorporated by Dr. Malkiel, brings his quantitative analysis up from 10.1% to 10.5%.

I would like to now comment on Dr. Malkiel's testimony on pages 23 through 28 wherein he rationalizes an allowable return on equity of 11.5% to 12.45%. On page 23 of his testimony, Dr. Malkiel opines that the reason that his current DCF cost of equity is significantly lower than the DCF cost he calculated during 2002, is because "the average yield on (riskless) 10-year U.S. Treasury securities was about one percentage point higher than today's 10-year rate. Then he states that "today's interest rate levels are unusually low." The insinuation, of course, is that the current interest rates (at the time of writing his testimony) are unusually low and we can expect higher rates in the near future. This allowed Dr. Malkiel to make the statement: "As rates rise, required rates of return for all assets are likely to rise. Thus, my minimum estimate of 10.5 percent for the required rate of return on SCE&G's equity will also rise as well. A more normal required return on equity is higher than 10.5 percent."

With respect to these statements I have several comments. First, Dr. Malkiel's statement that 10-year treasury rates are about one percentage point lower today than in 2002 is factually not correct. Dr. Malkiel conducted his DCF analysis for the 2002 rate case based on data as of August 1, 2002.[13] Dr. Malkiel's DCF analysis in this case was conducted based on data as of July 1, 2004. A comparison of the yields on 10-year treasuries immediately before and after each of these analyses is as follows:

	10-Year U.S. Treasury Yields[14]		
	2002 Case	2004 Case	Difference
Day - 2	4.65% (7/30/02)	4.70% (6/29/04)	+0.05%
Day - 1	4.51% (7/31/02)	4.62% (6/30/04)	+0.11%
Day of Analysis	4.47% (8/01/02)	4.57% (7/01/04)	+0.10%
Day + 1	4.33% (8/02/02)	4.48% (7/02/04)	+0.15%
Day + 2	4.29% (8/05/02)	4.49% (7/06/04)	+0.20%

As can be seen above, the 10-year treasury rate was actually about 10 basis points higher when Mr. Malkiel wrote his current testimony as compared to when he conducted his analysis in 2002.

Q. MR. WATKINS, YOUR COMPARISON OF 10-YEAR TREASURY YIELDS ABOVE ARE ONLY FOR A VERY SHORT PERIOD OF TIME. IS IT POSSIBLE THAT THERE WAS AN ABERRATION DURING THIS SHORT COMPARISON PERIOD?

A. Yes, it is possible. However, Dr. Malkiel conducts his DCF analysis based on the spot closing price of stock on a single day. Therefore, a short comparison period that matches with his DCF analysis is appropriate. However, the average 10-year treasury yield the month prior to Dr. Malkiel's 2002 analysis (July 2002) was 4.65%. The same security,

[13] Page 19 of Dr. Malkiel's direct testimony in Docket No. 2002-223-E.

[14] Per United States Treasury, daily price records see: http://ustreas.gov/offices/domestic-finance/debt-management/interest-rate/yield-hist.html.

one month prior to his current analysis was 4.73%. Again, about 10 basis points higher currently than in 2002.

Q. PLEASE CONTINUE.

A. Dr. Malkiel reasons that at the time of writing his current testimony, the Federal Funds rate was unusually low and that likely increases to this rate will force all interest and capital costs up. However, he fails to mention that investors and capital markets may have already anticipated such rate hikes by the Federal Reserve and that long-term capital costs reflect higher short-term interest rates already. To test Dr. Malkiel's assertion, we can simply observe how longer term interest rates have reacted to the Federal Reserve's actions. The Federal Reserve has raised the Federal Funds rate three times this year[15/] from1.00% to the current 1.75%. The following table shows the average monthly 10-year and 20-year Treasury yields from June 2004 through the present.

		U.S. Treasury Yield	
Fed. Reserve Action	Month	10-Yr.	20-Yr.
Increase 0.25%	June 2004	4.73%	5.45%
	July 2004	4.50%	5.24%
Increase 0.25%	August 2004	4.28%	5.07%
Increase 0.25%	September 2004	4.13%	4.89%
	Current (10/13/04)	4.09%	4.86%

15/ June 30, 2004 (0.25%); August 10, 2004 (0.25%); and September 21, 2004 (0.25%).

As can be seen above, there has been a steady decline in long term capital costs in spite of the Federal Reserve's increases to the short-term Federal Funds rate. Dr. Malkiel's hypothesis simply has not been correct.

Finally, on this topic of so called "abnormally low interest rates," Dr. Malkiel has consistently said that one cannot, nor should not, attempt to predict short term fluctuations in the market. Instead, investors should concentrate on the long term. For the long-term (next 10 years or so), Dr. Malkiel has publicly forecasted that the overall stock market will yield an annual return of about 8% over the next decade or so.[16/] Yet, he advocates an allowable return of up to 12.45% for this regulated utility, a company that is clearly less risky than the stock market overall.

Q. IS THERE ANOTHER REASON PROVIDED BY DR. MALKIEL TO SUPPORT HIS CONSIDERATION OF A RETURN HIGHER THAN HIS QUANTITATIVE ANALYSES?

A. Yes. The other reason Mr. Malkiel provides in support of an allowed return on equity of 12.45% is at odds with economic principles and legal precedent. On page 25 of his testimony, Dr. Malkiel reasons that because the Jasper facility (which cost about $500 million) was developed when the allowed ROE for SCE&G was 12.45%, that investors should be offered this level of return over the life of the facility. Since SCE&G's rate base is in excess of $3.5 billion, it follows that Dr. Malkiel would advocate the pricing of every

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16/ Interview on National Public Radio, May 2, 2003.

single plant or rate base item based on the capital costs in effect when that item was developed or constructed. I built my home in 1988 when mortgage rates were 9.5%. According to Dr. Malkiel's logic, banks should require that I continue to pay this level of interest today. I can assure this Commission that my current mortgage rate is nowhere near 9.5%.

Undoubtedly, Dr. Malkiel knows that capital costs are forward looking. This is a most basic financial and economic concept and is why the U.S. Supreme Court made the following finding in its seminal Bluefield Water Works v. Public Service Commission of West Virginia opinion (262 U.S. 679):

> "What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties;
>
> • • •
>
> A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

Lastly, I observe that there would be a never ending upward spiral, or ratchet, in capital costs under Dr. Malkiel's logic. If current and future investments are authorized a return on costs based on the higher of current or older cost of investments made, there is no possibility for capital costs to decline, only increase. Dr. Malkiel's discussion and logic is absolutely contrary to the principles and precedents that guide economists in estimating a fair rate of return for regulated utilities.

PART III: <u>Revenue Requirement</u>

A. <u>Summary of Adjustments</u>

Q. PLEASE SUMMARIZE YOUR OVERALL REVENUE REQUIREMENT FINDINGS AND RECOMMENDATIONS FOR THIS CASE.

A. My Schedule 8, which consists of two pages, incorporates each of my recommended ratemaking adjustments and determines the change in operating revenue necessary to achieve my recommended fair rate of return on rate base of 7.77%. As indicated on Schedule 8, a decrease in SCE&G's retail electric operating revenue of $39.125 million is required to achieve this fair rate of return and permit recovery of allowable expenses.

My Schedule 9, page 1 aggregates my adjustments relating to operating income, while page 2 of this schedule combins my rate base adjustments. The details underlying each ratemaking adjustment are provided in my Schedules 10 through 22.

B. **<u>Annualize NCEMC Contracts (Adjustment #1)</u>**

Q. PLEASE EXPLAIN THE COMPANY'S ADJUSTMENT TO ANNUALIZE THE NCEMC CONTRACTS.

A. In January 2004, two new wholesale sales contracts under which SCE&G sells system capacity to the North Carolina Electric Membership Cooperative (NCEMC) became effective. One contract is for 250MW and the other is for 100MW of supply. Because only three months experience (January-March) is reflected in test year revenue, it is appropriate to annualize this revenue for ratemaking purposes. Each of these contracts generates fixed capacity revenue and variable energy margins. The capacity charge revenues are fixed and do not vary by month. The energy margins vary depending on the kwh purchased. I have no disagreement with the annualized fixed charges. However, I do disagree with the Company's annualization of energy margins from these two contacts.

With respect to the energy margins from the 250MW contract, actual margins booked in the test year were $1,047,601. Ms. Walker then used the actual margins for April and most of May 2004, which were negative $737,033. For the remaining months of June through December, Ms. Walker then assumed a breakeven on energy, or zero margin. Ms. Walker's result is an annualization adjustment of $-737,033 to energy margins for the 250MW contract.

Q. WHAT IS THE BASIS FOR THE ASSUMED ZERO ENERGY MARGIN ASSOCIATED WITH THE 250MW CONTRACT?

A. SCE&G deems these contracts as confidential and has not provided them in discovery. However, the Company represented in an informal conference call that the energy charge actually billed to NCEMC is based on a hypothetical energy cost and the intent is to charge NCEMC a zero energy margin for this contract. I do not know the specifics of how the energy charge is calculated or the basis for the so-called hypothetical energy cost.

Q. PLEASE EXPLAIN WHY YOU DISAGREE WITH MS. WALKER'S 250MW MARGIN ADJUSTMENT OF $-737,033.

A. The energy margins may or may not net to zero over time as per the representations of SCE&G, but there is no way to evaluate this probability because these contracts have not been provided to the parties. More importantly, however, is the fact that the margin actually earned to date has been significantly positive. As such, I have annualized the actual energy margins billed for the first six months of the contract (January through June). My annualization results in an additional energy margin of $618,689 during the July through December period. As shown in schedule 10, this additional margin of $618,689, coupled with the actual margin during April through June yields a test year adjustment of $189,777.

Q. PLEASE EXPLAIN YOUR ADJUSTMENT ASSOCIATED WITH THE 100MW CONTRACT.

A. My adjustment method for this contract is identical to that used for the 250MW contract. That is, I annualized the actual January through June energy margins. My energy margin annualization results in a test year adjustment of $4,326,579 as compared to Ms. Walker's adjustment of $4,253,682.

Q. WHAT IS THE NET EFFECT OF YOUR NCEMC CONTRACT ADJUSTMENT?

A. On a retail basis, the net effect is to increase revenues $931,000 more than those proposed by Ms. Walker, as provided in my Schedule 10.

C. Purchased Power Settlement Costs (Adjustment #2)

Q. PLEASE EXPLAIN WHAT THIS ADJUSTMENT REPRESENTS.

A. From March 2001 through February 2003, SCE&G collected from ratepayers, all purchased power costs through the fuel clause mechanism. However, the fuel clause statute in effect at that time only allowed the recovery of fuel costs used in the Company's own generation.[17/] The Consumer Advocate appealed this allowance of total purchased power costs within the fuel clause and the Circuit Court reversed the allowed treatment and remanded the matter back to this Commission. Subsequent to the Circuit Court's ruling, SCE&G and the Consumer Advocate entered into a stipulation whereby the parties agreed to allow recovery from ratepayers the imputed non-fuel component of purchased power costs over time. The non-fuel component was stipulated to be 40% purchased power costs and totaled $25.618 million for the two years in question. In this year's fuel case (2004), under the terms of the stipulation, SCE&G's deferred fuel cost recovery balance was reduced by the $25.618 million and the parties agreed to allow re-recovery of this amount, over some

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17/ S.C. Code Ann. Sec. 58-27-865 (Supp. 2003).

period of time through base rates. The parties agreed to disagree on the time period (amortization period) in which this $25.618 million should be re-collected. SCE&G proposes a three year amortization period and I propose a five-year period for the following reasons.

It should be remembered that the $25.618 million was actually collected from ratepayers in a manner inconsistent with the existing statute. As such, this amount could have been refunded to customers and written off by the Company. As part of the settlement, the Consumer Advocate agreed to allow the re-recovery of this amount over some period of time. Considering this fact, it is my opinion that a 5-year amortization period is more equitable to ratepayers and still adheres to the stipulation. Moreover, if it is more than three years until SCE&G's next rate case, ratepayers will return more money to the Company than they paid improperly the first time. The effect of my adjustment is to reduce the Company's proforma O&M expenses by $3,179,000 (retail) and is provided in Schedule 11.

D. <u>Future Turbine Expenses and Investments (Adjustment #5)</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROPOSAL TO AMORTIZE FUTURE EXPENSE AND INVESTMENTS.

A. In short, the Company is proposing to collect from ratepayers now, what it forecasts future capital generation related expenditures to be in the future. Specifically, the Company proposes to amortize $67.7 million of "projected" turbine overhauls over eight years. These projected capitalized expenditure are forecasted to be made between 2005 and 2012. The following annual budgeted amounts are included in the $67.7 million forecast:

Year	Forecasted Expenditure ($ millions)[18/]
2005	$5,838
2006	$9,138
2007	$10,149
2008	$5,719
2009	$5,876
2010	$7,874
2011	$9,368
2012	$13,748
Total	$67,711

The Company is requesting a return on (cost of capital) and return of (depreciation) its current investment in turbines as well as to collect from ratepayers today, future capitalized turbine refurbishment costs. This proposal should be rejected as the costs are not known and measurable, but merely forecasts. Moreover, these investments will not be used and useful until well into the future (up to 8 years), and represent a double collection of investment costs.

For the record, the following amounts are projected by generating station:

18/ Per SCE&G response to Staff Data Request No. 1-62.

Name	(2005-2012 Projection ($ millions)[19/]
Canadys	$4.912
Cope	$4.145
Jasper	$23.946
McMeekin	$2.552
Urquhart (Gas)	$26.564
Urquhart (Steam)	$1.318
Wateree	$4.274
Total	$67.711

The effect of my adjustment is to reduce the Company's proforma O&M expenses by $5,038,000 (retail) and is shown on Schedule 12.

E. Ammonia Costs (Adjustment #6)

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. The Company recently installed selective catalytic reactors (SCR) at the Williams and Wateree stations to reduce ozone related emissions. This adjustment annualizes ammonia costs used by the SCRs. Ms. Walker used the cost of ammonia as of March 2004, and I have adjusted her amount to reflect the actual June costs of ammonia. Schedule 13 shows that the effect of my adjustment is to increase the Company's proforma O&M expenses by $17,000 (retail).

[19/] Per SCE&G response to Staff Data Request No. 1-62.

F. Wages, Benefits, and Payroll Taxes (Adjustment #7)

Q. PLEASE EXPLAIN THIS ADJUSTMENT.

A. Ms. Walker adjusts actual test year payroll expense to reflect current (March 2004) payroll levels. There are also attendant adjustments to reflect employee benefits and payroll taxes. While I have not reviewed the specifics of the March 2004 payroll to ensure that abnormal or annual bonuses were not booked in that month, I will defer to Staff's audit to verify the reasonableness of using March payroll, as is.

However, I have made an adjustment to the Company's proforma payroll (and payroll tax) amounts. My adjustment relates to test year officer and employee bonuses. During the test year, the Company paid $4,938,540 in electric employee bonuses, and $6,549,083 in electric-related executive bonuses.

With regards to employee bonuses, the Company stated in response to Staff Data Request No. 1-77:

> SCANA's 2003 Employee Bonus Incentive Plan was based on the achievement of business unit strategic goals (50%), SCANA earnings per share (25%) and subsidiary earnings per share (25%) or SCANA earnings per share for SCANA Services employees. Business unit goals were comprised of three to five goals extracted from the operating units' strategic plan. EPS targets were established prior to the plan year.

With respect to executive bonuses, SCE&G referred the Staff in Request No. 1-90 to the SCANA Corporation 2004 Proxy statement. The Proxy statement contains the following regarding executive compensation:

> SCANA's executive compensation program is designed to support SCANA's overall objective of creating shareholder value by:
>
> - Hiring and retaining premier executive talent;
>
> - Having a pay-for-performance philosophy linking total rewards to achievement of corporate and business unit goals;
>
> - Placing a substantial portion of pay for senior executives "at-risk" and aligning the interests of executives with the long-term interests of shareholders through equity-based compensation; and,
>
> - Balancing elements of the compensation program to reflect SCANA's financial, customer-oriented and strategic goals.
>
> SCANA's Annual Incentive Plan promotes SCANA's pay-for-performance philosophy, as well as its goal of having a meaningful amount of executive pay "at-risk." Through this plan, financial incentives are provided in the form of annual cash bonuses.

Both employee and executive bonuses are based primarily in meeting or exceeding profitability goals and enhancing shareholder value. Bonuses due to higher than expected profit levels should be paid out with profits, and not borne by captive ratepayers. However, I recognize that increased profitability can and does come, in part, from increased efficiency, which will benefit ratepayers in the long run. Therefore, I recommend a 50/50 sharing of the cash bonus between shareholders and ratepayers. The effect of my adjustment is to reduce SCE&G's proforma O&M expenses by $5,513,000 (retail) and reduce payroll taxes by $422,000 as shown in my Schedule 14.

G. **Health Care Costs (Adjustment 8C)**

Q. PLEASE EXPLAIN THE COMPANY'S HEALTH CARE COST ADJUSTMENT.

A. Ms. Walker adjusts actual test year health care costs of $27,832,606 (total SCE&G) to reflect what she considers to be a normalized, or going level amount ($30,161,988). Ms. Walker proposes to increase actual test year amounts by 8.4%. This amount was developed by averaging the three months health care expense for January, February, and March in 2004, and then multiplying this average by twelve. The health care cost details provided in response to Staff Audit Request No. 32 indicate that SCE&G is self insured and uses pay-as-you-go accounting. The following are the monthly total SCE&G health care costs during the test year:

April 2003	$2,371,497
May 2003	2,821,137
June 2003	1,855,129
July 2003	2,761,625
August 2003	2,639,444
September 2003	2,364,486
October 2003	2,303,450
November 2003	2,483,569
December 2003	691,777
January 2004	2,277,954
February 2004	1,229,560
March 2004	4,032,983
Total	$27,832,606

As can be seen above, the March 2004 expense was abnormally high and the February expense was abnormally low. These are two of the three months that Ms. Walker used to adjust actual expense. Since test year health care expenses fluctuated significantly, it could be reasoned that no adjustment is necessary since there is no clear upward trend in the Company's health care expenses during the test year. However, there is a general consensus that health care costs are rising faster than inflation. Therefore, I have also adjusted actual test year amounts to reflect higher health care costs.

The annual increase (inflation) in health care costs (first half of 2003 to first half of 2004) in the Southern United States as reported by the U.S. Department of Labor, Bureau of Labor statistics is:

3.9% for all Southern Urban consumers;
4.1% for Southern consumers in metropolitan areas of 50,000-1,500,000 population; and,
3.2% for Southern consumers in metropolitan areas with less than 50,000 population.

So as not to quibble, I selected the highest of the four healthcare inflation rates (4.1%) and applied this inflation rate to actual test year health care costs. This adjustment results in a decrease to the Company's proforma O&M expenses of $508,000 (electric retail) and is provided in my Schedule 15.

H. <u>Future Transmission Investment and Expenses (Adjustment #13C)</u>

Q. PLEASE EXPLAIN SCE&G'S PROPOSED ADJUSTMENT FOR FUTURE NERC INVESTMENT AND EXPENSES.

A. The Company proposes to increase General Plant in Service to reflect its projected investment and costs associated with equipment and software to enhance planning and monitoring of its transmission system. Specifically, the Company estimates these future investment costs to include $240,000 for software, $481,000 for electronic equipment, $370,000 in future external contractor costs, and $218,000 in allocated future internal labor. The total projected capitalized investment totals $1,309,000. In addition, the Company anticipates that it will hire eight new employees at an average salary of $80,000 per year, and incur an additional $180,000 per year in consultant and contractor costs. These forecasted expenses (including a provision for employee benefits) total $1,050,000 per year.

As with the Company's proposal to include in rates its projected future investment in turbine costs (Adjustment #5), this adjustment should be rejected as the investment amounts are not in service and the proposal reflects estimates or forecasted amounts for future cost. To the extent actual investment has been made through the time of Staff's cut-off period, I do not object to actual amounts being included in rate base. My Schedule 16 reverses SCE&G's proposal. The effect of my adjustment is to reduce the Company's proforma plant in service by $1,257,000 (retail), reduce depreciation reserve by $46,000 (retail), reduce O&M expenses by $988,000 (retail) and reduce depreciation expense by $46,000 (retail).

I. <u>Jasper Generation Project Adjustments (Adjustment #17)</u>

Q. PLEASE EXPLAIN SCE&G'S ADJUSTMENTS RELATING TO THE JASPER GENERATION FACILITY.

A. Now that the Jasper generation facility is completed and in service, the Company proposes several plant adjustments to reduce construction work in progress (CWIP), increase plant in service, and begin taking depreciation expense on the facility. SCE&G also proposes to annualize the O&M expenses associated with running the Jasper facility and include its requested fixed gas (fuel) supply costs in base rates (and remove from the fuel clause). My adjustment to the Company's proposed amounts is related to SCE&G's request to include fixed gas supply costs in base rates.

SCE&G proposes to remove $15,292,800 in fixed contract gas supply costs from its fuel clause and place this amount into base rates ($14,397,547 allocated to retail). This exact amount is in dispute and is being contested in another pending proceeding before the Commission (Docket No. 2004-126-E). My testimony in that pending docket is filed under seal due to SCE&G's assertions that it contains competitively sensitive information affecting its unregulated affiliates. Legal counsel has advised me that I should not discuss or explain specifics of the dispute over Jasper's fixed as supply costs. I can say, however, that I have concluded the amount in question ($15.293 million) is grossly excessive. Because the requested amount is being contested in a separate docket, this Commission should not include Jasper's fixed gas supply costs in base rates until that matter is resolved. I reiterate that the Company is currently collecting the full $15.293 million in fuel clause revenue and will continue to do so until the Commission makes a finding in Docket No. 2004-126-E. The effect of my adjustment is to reduce SCE&G's proforma O&M expenses by $14,398,000 (retail), and is shown on Schedule 17.

J. <u>Fossil Fuel Inventory (Adjustment #19)</u>

Q. PLEASE EXPLAIN THE COMPANY'S PROFORMA ADJUSTMENT TO FOSSIL FUEL INVENTORIES.

A. SCE&G proposes to increase actual average test year coal inventories to reflect (a) forecasted coal prices; and (b) desired inventory tonnages. I have two disagreements regarding the Company's proposed coal inventory adjustment. First, actual, not forecasted coal prices should be used. I have adjusted actual test year coal prices per ton to reflect current (June 2004) actual prices. My second disagreement relates to the Company's use of desired or projected coal inventories (tons of coal). SCE&G claims that actual test year coal inventories were lower than usual due to excess demand in the coal markets and rail transportation constraints. Whether coal inventories are or are not below some desired level is immaterial. For whatever reason, the Company's level of coal inventories have not increased. As shown in my Schedule 18, the following are SCE&G's monthly coal inventory tonnages during the test year:

Month	Coal Inventory (tons)
April 2003	715,226
May 2003	684,427
June 2003	634,350
July 2003	477,087
August 2003	472,510
September 2003	502,433
October 2003	590,053
November 2003	599,239
December 2003	549,428
January 2004	378,839
February 2004	338,342
March 2004	347,321
Average	524,106

As of June 30, 2004, SCE&G's coal inventory totaled 399,875 tons.[20] This level is well below the average test year amount (524,106 tons) or that in inventory in June 2003 (634,350). Since coal inventories are part of materials and supplies, which are included in the rate base, the Company should not be allowed to earn a return on inventory levels it does not have. Therefore, I have adjusted the Company's desired coal tonnages to reflect actual average test year levels. The effect of my adjustment is to reduce the Company's proforma materials and supplies by $18,841,000 (retail).

I am aware that SCE&G has agreed to revise its coal inventory adjustment contained in the filing and I have reviewed the Company's revised calculations. These revised calculations continue to include forecasted coal prices and desired inventory levels. As a note, my dollar adjustment relates to the amount in the Company's filing since I adjust from the Company's filed proforma amounts.

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[20] Per SCE&G response to Columbia Energy #1-27.

K. **<u>GridSouth (Adjustment #20)</u>**

Q. **PLEASE EXPLAIN WHAT THE COMPANY'S GRIDSOUTH ADJUSTMENT REPRESENTS.**

A. GridSouth was a failed attempt to create a "for profit" RTO. This RTO would have been owned by Duke Power, Progress Energy-Carolinas, and SCE&G. SCE&G sought recovery of these costs in the 2002 rate case and they were denied by the Commission. The Company is again seeking recovery of these expenses from retail ratepayers.

Q. **WHAT WERE THE COMMISSION'S FINDINGS REGARDING GRIDSOUTH COSTS IN THE 2002 RATE CASE?**

A. In Order No. 2003-38 at p. 16 and p. 17, the Commission made the following findings:

(a) most of the costs were incurred before the test year;

(b) not much detail was provided by the Company as to the nature of the investment in the project;

(c) the Company has not met its burden for cost recovery at this time;

(d) Staff concluded that since GridSouth was not operational during the test year, it should not have been considered used and useful during that time, although it might have been considered property held for future use;

(e) the costs involved were imposed as a result of FERC mandates;

(f) it is premature to allow recovery of GridSouth costs at the retail level at this time; and,

(g) the door should remain open on this issue, and that allowance of GridSouth costs should be deferred until such time as the Company can meet its burden of proof, and/or until FERC rules on the allowance of the expenditures at the wholesale level.

Q. WITH RESPECT TO SCE&G MEETING ITS BURDEN OF PROOF, HAS THE COMPANY INTRODUCED ADDITIONAL EVIDENCE IN THIS CASE THAT WAS NOT ADMITTED IN THE 2002 CASE.

A. No, other than a statement by Mr. Lorick at pages 16-17 of his Direct Testimony that all assets of GridSouth have now been disposed of and there will be no future utilization of this vehicle for transmission, or any other purposes.

Q. HAS THE FERC RULED ON THE ALLOWANCE OF THE EXPENDITURES AT THE WHOLESALE LEVEL?

A. It is my understanding that it has not. In fact, Mr. Lorick states on page 16 of his testimony: "Until the regulatory future becomes more certain, the structure, operational requirements, and responsibilities of RTOs, particularly one like GridSouth, is virtually unknowable."

Q. SHOULD ANY GRIDSOUTH COSTS BE ALLOWED IN THIS RATE CASE?

A. GridSouth costs should not be allowed in this case, for the reasons expressed by the Commission in Order No. 2003-38, as well as the reasons I explained in my direct testimony in the 2002 case.

Q. WHAT REASONS DID YOU PROVIDE FOR DISALLOWANCE OF GRIDSOUTH COSTS IN THE 2002 RATE CASE?

A. First, GridSouth is a failed business venture and shareholders, not ratepayers, should be responsible for such a failure. Second, although the FERC granted provisional acceptance of the applicant's (GridSouth owners) filing with certain modifications, it had serious concerns regarding the independence of the RTO. FERC required modifications to the GridSouth application to accommodate these independence concerns.

Largely as a result of its requirements for a totally independent RTO, FERC put SCE&G, Duke and CP&L on notice as late as March 28, 2001[21/] that the companies (proposed RTO) may not spend funds on activities that are significant to the future operation

[21/] See GridFlorida Order dated March 28, 2001 (94 FERC 61,363); CP&L, et.al. Order dated May 30, 2001 (95 FERC 61,282); and GridSouth Order dated July 12, 2001 (96 FERC 61,067).

of the RTO and may only expend funds on certain non-policy related matters. According to the July 12, 2001 GridSouth Order, "the GridSouth Applicants represented that they would similarly limit their spending prior to the seating of the independent Board."[22]

Finally, I posed 17 questions that should be answered before any consideration was given to the allowance of GridSouth costs. Most of these 17 questions remain unanswered today.

Q. WHAT WERE THE 17 GRIDSOUTH QUESTIONS YOU POSED IN THE 2002 RATE CASE?

A. I recommended, and continue to recommend, that the following questions should be answered before any allowance of GridSouth costs is considered:

(1) Was the purpose of the proposed for-profit RTO primarily for the benefit of wholesale customers and additional profit for SCE&G shareholders?

(2) What, if any, quantifiable benefits would retail customers receive from the proposed for-profit RTO?

(3) Why did SCE&G insist on a for-profit RTO?

(4) Should the cost recovery of expended Gridsouth costs be reflected only in FERC approved wholesale rates?

[22] 96 FERC 61,067.

(5) Should South Carolina retail customers pay for almost all of the Gridsouth costs as proposed by SCE&G?

(6) Did the FERC abruptly change gears on the Gridsouth project through no fault of SCE&G?

(7) Did SCE&G, Duke and CP&L jump the gun in investing in GridSouth given the FERC's directions and orders to the contrary?

(8) Were all costs prudently incurred?

(9) Should retail ratepayers pay for the imputed carrying charges included in GridSouth's assets?

(10) What, if any, investment assets are salvageable?

(11) Will SCE&G join a RTO in the foreseeable future?

(12) What will FERC do with respect to the already expended costs when SCE&G does join or form an RTO, and makes a FPA Section 205 filing?

(13) Should shareholders be totally insulated from this failed business venture? If not, what sharing of the pain is fair?

(14) Has SCE&G acted openly in disclosing information regarding GridSouth?

(15) Has SCE&G actually incurred these costs?

(16) What, if any, tax benefits has (or will) SCE&G receive from its expenditures in GridSouth?

(17) Is SCE&G seeking double recovery of Gridsouth costs?

Q. WHAT IS THE EFFECT OF YOUR REVERSAL OF GRIDSOUTH COSTS?

A. As shown on my Schedule 19, O&M expenses are reduced by $2.641 million (retail) and rate base is reduced by $6.552 million (retail).

L. <u>Cash Working Capital (Adjustment #24)</u>

Q. PLEASE DISCUSS THE COMPANY'S CASH WORKING CAPITAL ADJUSTMENT.

A. Company witness Walker employed the Commission approved " ⅛ O&M Expenses (Less Fuel)" cash working capital (CWC) methodology in her analysis. She applied this methodology to test year per book amounts, and then to her proforma adjustments. Given the Commission's prior findings, I have accepted this methoodlogy in this case. Due to my various O&M expense adjustments, my Cash Working Capital adjustment differs from the Company. My CWC adjustment reduces SCE&G's CWC proforma amount by $4,031,000 (retail) as shown in schedule 20.

Although I have used the same formula approach as used by SCE&G to estimate cash working capital in this analysis, I do not believe this formula approach is the appropriate methodology for larger utilities such as SCE&G. I note that my cash working capital adjustment differs from the Company's due to the effect of my other O&M expense adjustments.

Q. WHY IS THE FORMULA APPROACH NOT APPROPRIATE FOR LARGER UTILITIES SUCH AS SCE&G?

A. The formula approach is a "one size fits all" methodology in which cash working capital is estimated as $\frac{1}{8}$ of non-fuel O&M expenses. Although this approach is arbitrary, it is a reasonable ratemaking guideline for very small regulated utilities, such as Class B&C water and sewer utilities, and smaller electric cooperatives. The historical rationale for the use of the formula approach is that the additional accuracy and benefits provided by a lead-lag study are not offset by the costs to perform a lead-lag study for very small utilities. This is not the case with major utilities such as SCE&G with a jurisdictional rate base exceeding $3 billion. Virtually every other jurisdiction requires lead lag studies for major utilities, and beginning in 1981 the FERC required lead-lag studies for all electric and gas rate cases.

I recognize that lead-lag studies add an additional expense to utilities' rate case expenses (in which ratepayers pay for), however, the additional accuracy of a lead-lag study far outweighs this minor cost when compared to a rate increase request of $113 million. Therefore, I recommend the Commission direct SCE&G to perform a lead-lag study in its next rate case, and if SCE&G chooses not to do so, not include any cash working capital in its rate base.

M. <u>Interest Synchronization (Adjustment # 22)</u>

Q. PLEASE EXPLAIN WHAT INTEREST SYNCHRONIZATION REPRESENTS AND HOW IT IS USED IN THE RATEMAKING PROCESS.

A. Interest synchronization relates to matching interest expense to the embedded cost of debt and capital structure used for cost of capital purposes. Specifically, actual interest expense is adjusted to reflect proforma rate base and the weighted cost of debt used in the overall cost of capital. This adjustment effects state and federal income taxes.

My interest synchronization adjustment differs from the Company's adjustment due to my other rate base adjustments and a different capital structure than that used in the filing.

Q. HAVE YOU MADE AN INTEREST SYNCHRONIZATION ADJUSTMENT IN THIS CASE?

A. Yes. I have actually made two interest synchronization adjustments, which are shown in my Schedule 21. The first interest adjustment corrects for errors in the Company's application. The second adjustment is required to recognize the effect of my other ratemaking adjustments and recommended weighted cost of debt.

Q. PLEASE EXPLAIN THE ERROR IN THE COMPANY'S APPLICATION AS IT RELATES TO INTEREST SYNCHRONIZATION.

A. The Company's application (Exhibit D-II and D-III) overstates state and federal income taxes due to improper recognition of interest expense.

In order to explain this error, it must be recognized that SCE&G's requested rate of return on rate base of 9.18% is comprised of a debt return (interest expense) of 3.05%[23/] and an overall equity return (preferred + common) of 6.13%.[24/] Therefore, for every $100 of rate base, SCE&G is requesting an interest return of $3.05 and an after tax equity return of $6.13. The Debt return (interest expense) is not subject to income taxes. However, income taxes must be paid on the allowed equity return such that the before tax return on equity required to generate an after tax return of 6.13% is about 9.925%. Stated differently (and more simply), interest expense (3.05%) is deductible for income taxes purposes, while tax must be paid on the before tax equity return of (9.925%).

SCE&G's error rests in the fact that it has not calculated income taxes based on the above requested return levels. That is, SCE&G did not properly deduct interest (3.05% of rate base) for income taxes. Rather, the Company only deducted interest expense booked during the test year which is less than that necessary under the Company's requested cost of capital. This error results in an overstatement of income taxes, (before accounting adjustments) of $6.050 million total electric and $5.756 million retail electric. This error, and the required interest and income tax adjustment required under the Company's proposed cost of capital, is shown in my Schedule 22.

[23/] 46.53% debt x 6.56% cost rate.

[24/] (2.71% preferred stock x 6.40% cost rate) + (50.76% common equity x 11.75% cost rate).

I note that Ms. Walker applies an interest synchronization adjustment properly to her incremental proforma accounting adjustments. My interest synchronization adjustment shown in Schedule 21 adjusts for the error discussed above (using my recommend weighted cost of debt) and reflects my incremental ratemaking adjustments. My total interest synchronization adjustment decreases state income taxes expense by $0.795 million and decreases federal income tax expense by $5.846 million.

PART IV: <u>CONCLUDING COMMENTS</u>

Q. DO YOU HAVE ANY OTHER COMMENTS REGARDING YOUR INVESTIGATION OF SCE&G'S APPLICATION IN THIS CASE?

A. Yes. In my direct testimony in SCE&G's last rate case I felt compelled to report to the Commission SCE&G's lack of cooperation and its direct attempt to stifle my investigation. Such has not been the situation in this case. The Company has responded to my discovery requests in this case in a responsive and good faith manner. Moreover, SCE&G has informally responded to questions arising during my investigation.

The review and investigation of any utility rate application is a very time consuming and costly undertaking. The less information provided by utilities in their applications requires even more time to be spent on understanding the adjustments and proposals, and increases the time and cost of discovery.

In this regard, I recommend that this Commission direct SCE&G to provide the following minimum additional documents as part of its next general rate case:

(a) all accounting adjustment work papers (similar to those provided in response to Staff Data Request No. 1-62); and,

(b) a complete cost of service study showing jurisdictional and class allocations on a per books, proforma, and proposed basis (as provided in response to Staff Data Request No. 1-33).

These requirements will not place any additional burden on the Company since these documents are already prepared and available to the Company. Moreover, my recommendation would serve to streamline the regulatory process and save time and money for the Staff and other intervenors.

Q. DOES THIS COMPLETE YOUR TESTIMONY?

A. Yes.

APPENDIX

RESUME OF
GLENN A. WATKINS

BACKGROUND & EXPERIENCE PROFILE

GLENN A. WATKINS

VICE PRESIDENT/SENIOR ECONOMIST

TECHNICAL ASSOCIATES, INC.

EDUCATION

1982 - 1988	M.B.A., Virginia Commonwealth University, Richmond, Virginia
1980 - 1982	B.S., Economics; Virginia Commonwealth University
1976 - 1980	A.A., Economics; Richard Bland College of The College of William and Mary, Petersburg, Virginia

POSITIONS

Jul. 1995-Present	Vice President/Senior Economist, Technical Associates, Inc.
Mar. 1993-1995	Vice President/Senior Economist, C. W. Amos of Virginia
Apr. 1990-Mar. 1993	Principal/Senior Economist, Technical Associates, Inc.
Aug. 1987-Apr. 1990	Staff Economist, Technical Associates, Inc., Richmond, Virginia
Feb. 1987-Aug. 1987	Economist, Old Dominion Electric Cooperative, Richmond, Virginia
May 1984-Jan. 1987	Staff Economist, Technical Associates, Inc.
May 1982-May 1984	Economic Analyst, Technical Associates, Inc.
Sep. 1980-May 1982	Research Assistant, Technical Associates, Inc.

EXPERIENCE

I. Public Utility Regulation

A. Costing Studies-- Conducted, and presented as expert testimony, numerous embedded and marginal cost of service studies. Cost studies have been conducted for electric, gas, telecommunications, water, and wastewater utilities. Analyses and issues have included the evaluation and development of alternative cost allocation methods with particular emphasis on ratemaking implications of distribution plant classification and capacity cost allocation methodologies. Distribution plant classifications have been conducted using the minimum system and zero-intercept methods. Capacity cost allocations have been evaluated using virtually every recognized method of allocating demand related costs (e.g., single and multiple coincident peaks, non-coincident peaks, probability of loss of load, average and excess, and peak and average).

Embedded and marginal cost studies have been analyzed with respect to the seasonal and diurnal distribution of system energy and demand costs, as well as cost effective approaches to incorporating energy and demand losses for rate design purposes. Economic dispatch models have been evaluated to determine long range capacity requirements as well as system marginal energy costs for ratemaking purposes.

B. Rate Design Studies -- Analyzed, designed and provided expert testimony relating to rate structures for all retail rate classes, employing embedded and marginal cost studies. These rate structures have included flat rates, declining block rates, inverted block rates, hours use of demand blocking, lighting rates, and interruptible rates. Economic development and special industrial rates have been developed in recognition of the competitive environment for specific customers. Assessed alternative time differentiated rates with diurnal and seasonal pricing structures. Applied Ramsey (Inverse Elasticity) Pricing to marginal costs in order to adjust for embedded revenue requirement constraints.

C. Forecasting and System Profile Studies -- Development of long range energy (Kwh or Mcf) and demand forecasts for rural electric cooperatives and investor owned utilities. Analysis of electric plant operating characteristics for the determination of the most efficient dispatch of generating units on a system-wide basis. Factors analyzed include system load requirements, unit generating capacities, planned and unplanned outages, marginal energy costs, long term purchased capacity and energy costs, and short term power interchange agreements.

D. Cost of Capital Studies -- Analyzed and provided expert testimony on the costs of capital and proper capital structures for ratemaking purposes, for electric, gas, telephone, water, and wastewater utilities. Costs of capital have been applied to both actual and hypothetical capital structures. Cost of equity studies have employed comparable earnings, DCF, and CAPM analyses. Econometric analyses of adjustments required to electric utilities cost of equity due to the reduced risks of completing and placing new nuclear generating units into service.

E. Accounting Studies -- Performed and provided expert testimony for numerous accounting studies relating to revenue requirements and cost of service. Assignments have included original cost studies, cost of reproduction new studies, depreciation studies, lead-lag studies, Weather normalization studies, merger and acquisition issues and other rate base and operating income adjustments.

II. Transportation Regulation

A. Oil and Products Pipelines -- Conducted cost of service studies utilizing embedded costs, I.C.C. Valuation, and trended original cost. Development of computer models for cost of service studies utilizing the "Williams" (FERC 154-B) methodology. Performed alternative tariff designs, and dismantlement and restoration studies.

B. Railroads -- Analyses of costing studies using both embedded and marginal cost methodologies. Analyses of market dominance and cross-subsidization, including the implementation of differential pricing and inverse elasticity for various railroad commodities. Analyses of capital and operation costs required to operate "stand alone" railroads. Conducted cost of capital and revenue adequacy studies of railroads.

III. Insurance Studies

Conducted and presented expert testimony relating to market structure, performance, and profitability by line and sub-line of business within specific geographic areas, e.g. by state. These studies have included the determination of rates of return on Statutory Surplus and GAAP Equity by line - by state using the NAIC methodology, and comparison of individual insurance company performance vis a vis industry Country-Wide performance.

Conducted and presented expert testimony relating to rate regulation of workers compensation, automobile, and professional malpractice insurance. These studies have included the determination of a proper profit and contingency factor utilizing an internal rate of return methodology, the development of a fair investment income rate, capital structure, cost of capital.

Other insurance studies have included testimony before the Virginia Legislature regarding proper regulatory structure of Credit Life and P&C insurance; the effects on competition and prices resulting from proposed insurance company mergers, maximum and minimum expense multiplier limits, determination of specific class code rate increase limits (swing limits); and investigation of the reasonableness of NCCI's administrative assigned risk plan and pool expenses.

IV. <u>Anti-Trust and Commercial Business Damage Litigation</u>

Analyses of alleged claims of attempts to monopolize, predatory pricing, unfair trade practices and economic losses. Assignments have involved definitions of relevant market areas(geographic and product) and performance of that market, the pricing and cost allocation practices of manufacturers, and the economic performance of manufacturers' distributors.

Performed and provided expert testimony relating to market impacts involving automobile and truck dealerships, incremental profitability, the present value of damages, diminution in value of business, market and dealer performance, future sales potential, optimal inventory levels, fair allocation of products, financial performance; and business valuations.

MEMBERSHIPS AND CERTIFICATIONS

Member, Association of Energy Engineers (1998)
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts (1992)
Member, American Water Works Association
National Association of Business Economists
Richmond Association of Business Economists
National Economics Honor Society

Exhibit__(GAW-1)
Schedule 1

SCE&G SHORT- TERM DEBT OUTSTANDING
(JAN. 1999 - JUNE 2004)

	1999	2000	2001	2002	2003	2004
January	$201,500,000	$259,904,000	$293,384,000	$236,690,000	$121,871,000	$294,275,000
February	$208,100,000	$224,709,000	$151,942,000	$88,756,000	$153,806,000	$175,444,000
March	$77,500,000	$186,698,000	$93,454,000	$97,864,000	$114,051,000	$191,065,000
April	$122,700,000	$179,617,000	$109,968,000	$161,133,000	$195,884,000	$224,356,000
May	$103,900,000	$150,681,000	$117,307,000	$161,498,000	$61,831,000	$168,476,000
June	$94,700,000	$136,123,000	$116,463,000	$212,931,000	$213,357,000	$167,960,000
July	$135,000,000	$138,969,000	$130,270,000	$244,341,000	$199,586,000	
August	$102,300,000	$103,161,000	$106,173,000	$257,526,000	$177,402,000	
September	$79,500,000	$105,430,000	$74,774,000	$248,620,000	$196,220,000	
October	$74,032,000	$113,391,000	$85,828,000	$205,599,000	$175,371,000	
November	$54,100,000	$118,661,000	$83,030,000	$115,615,000	$66,632,000	
December	$143,100,000	$187,717,000	$164,845,000	$177,702,000	$140,131,000	

Source: SCE&G response to CA # 1-62.

SCANA & COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	June, 2004 - August, 2004 Stock Prices HIGH	LOW	AVERAGE	YIELD
Comparison Group					
Energy East	$1.04	$24.77	$23.23	$24.00	4.33%
NSTAR	$2.22	$48.88	$46.01	$47.45	4.68%
Pinnacle West	$1.80	$42.99	$39.46	$41.23	4.37%
Vectren	$1.14	$25.75	$23.34	$24.55	4.64%
Wisconsin Energy	$0.84	$33.00	$30.90	$31.95	2.63%
WPS Resources	$2.22	$48.81	$45.00	$46.91	4.73%
Average					**4.23%**
SCANA	$1.46	$37.94	$35.32	$36.63	**3.99%**

Source: Standard & Poor's Stock Guide and Yahoo Finance daily prices..

SCANA & COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	5 yr Historical	5 yr Forecast
Comparison Group		
Energy East	6.0%	3.5%
NSTAR	4.5%	4.5%
Pinnacle West	5.3%	4.0%
Vectren	2.9%	4.5%
Wisconsin Energy	4.7%	6.5%
WPS Resources	2.2%	4.0%
Average	**4.3%**	4.5%
SCANA	4.2%	5.0%

Source: Value Line Investment Survey.

SCANA & COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '01-'03 to '07-'09 Growth Rates EPS	DPS	BVPS	Average w/ BVPS	Average w/o BVPS
Comparison Group									
Energy East	4.0%	6.0%	4.5%	4.8%	3.5%	5.0%	4.0%	4.2%	4.3%
NSTAR	4.5%	2.5%	2.5%	3.2%	3.0%	2.5%	4.5%	3.3%	2.8%
Pinnacle West	1.5%	7.5%	4.5%	4.5%	4.0%	4.5%	4.0%	4.2%	4.3%
Vectren	--	--	--		5.5%	3.0%	3.5%	4.0%	4.3%
Wisconsin Energy	9.0%	-12.0%	2.0%	-0.3%	4.5%	4.0%	7.0%	5.2%	4.3%
WPS Resources	7.0%	2.0%	5.0%	4.7%	5.0%	2.0%	5.5%	4.2%	3.5%
Average	5.2%	1.2%	3.7%	**3.4%**	4.3%	3.5%	4.8%	**4.2%**	**3.9%**
SCANA	3.0%	-3.0%	4.5%	**1.5%**	5.5%	5.5%	5.5%	**5.5%**	**5.5%**

Source: Value Line Investment Survey.

SCANA & COMPARISON COMPANIES
DCF COST RATES

COMPANY	ACTUAL YIELD	DCF ADJUSTED YIELD [D (1+.5G)]/P	HISTORIC RETENTION GROWTH	HISTORIC EPS GROWTH	HISTORIC AVERAGE GROWTH	DCF	DCF ADJUSTED YIELD [D (1+.5G)]/P	PROSPECTIVE RETENTION GROWTH	PROSPECTIVE PER SHARE GROWTH (w/o BVPS)	FIRST CALL EPS GROWTH	PROSPECTIVE AVERAGE GROWTH	DCF RATES
Comparison Group												
Energy East	4.33%	4.44%	6.0%	4.0%	5.0%	9.4%	4.42%	3.5%	4.3%	4.0%	3.9%	8.3%
NSTAR	4.68%	4.78%	4.5%	4.5%	4.5%	9.3%	4.77%	4.5%	2.8%	5.0%	4.1%	8.9%
Pinnacle West	4.37%	4.44%	5.3%	1.5%	3.4%	7.9%	4.46%	4.0%	4.3%	4.0%	4.1%	8.5%
Vectren	4.64%	4.71%	2.9%	--	2.9%	7.6%	4.77%	4.5%	4.3%	7.0%	5.3%	10.0%
Wisconsin Energy	2.63%	2.72%	4.7%	9.0%	6.9%	9.6%	2.70%	6.5%	4.3%	6.0%	5.6%	8.3%
WPS Resources	4.73%	4.84%	2.2%	7.0%	4.6%	9.4%	4.83%	4.0%	3.5%	5.0%	4.2%	9.0%
Average		4.32%	4.3%	5.2%	4.5%	**8.9%**	4.32%	4.5%	3.9%	5.2%	4.5%	**8.8%**
Median						**9.4%**						**8.7%**
SCANA	3.99%	4.06%	4.2%	3.0%	3.6%	**7.7%**	4.09%	5.0%	5.5%	4.5%	5.0%	**9.1%**

Sources: Prior pages of this schedule.

Exhibit___(GAW-1)
Schedule 3

SCANA & COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Comparison Group				
Energy East	5.25%	0.80	6.60%	10.5%
NSTAR	5.25%	0.70	6.60%	9.9%
Pinnacle West	5.25%	0.80	6.60%	10.5%
Vectren	5.25%	0.75	6.60%	10.2%
Wisconsin Energy	5.25%	0.70	6.60%	9.9%
WPS Resources	5.25%	0.75	6.60%	10.2%
Average	5.25%	0.75	6.60%	**10.2%**
				10.2%
SCANA	5.25%	0.70	6.60%	9.9%

Sources: Value Line Investment Survey, Ibbotson 2004 Annual yearbook, and U.S. Treasury daily yields.

Exhibit__(GAW-1)
Schedule 4

SCANA & COMPARISON COMPANIES
DCF COST RATES
SCPUC Approved Aproach in Docket No. 2002-223-E

COMPANY	ACTUAL YIELD	DCF ADJUSTED YIELD [D (1+.5G)]/P	PROSPECTIVE EPS GROWTH VALUE LINE	FIRST CALL	AVERAGE GROWTH	DCF	DCF ADJUSTED YIELD [D (1+G)]/P	DCF
Comparison Group								
Energy East	4.33%	4.41%	3.5%	4.0%	3.8%	8.2%	4.50%	8.2%
NSTAR	4.68%	4.77%	3.0%	5.0%	4.0%	8.8%	4.87%	8.9%
Pinnacle West	4.37%	4.45%	4.0%	4.0%	4.0%	8.5%	4.54%	8.5%
Vectren	4.64%	4.79%	5.5%	7.0%	6.3%	11.0%	4.93%	11.2%
Wisconsin Energy	2.63%	2.70%	4.5%	6.0%	5.3%	7.9%	2.77%	8.0%
WPS Resources	4.73%	4.85%	5.0%	5.0%	5.0%	9.9%	4.97%	10.0%
Average	4.23%	4.33%	4.25%	5.17%	4.71%	**9.0%**	4.43%	**9.1%**
Median						**8.6%**		**8.7%**
SCANA	3.99%	4.09%	5.5%	4.5%	5.0%	**9.1%**	4.19%	**9.2%**

Source: Schedule 2.

Exhibit___(GAW-1)
Schedule 5

SCE&G RETAIL ELECTRIC
CAPITAL STRUCTURE & COST OF CAPITAL
SCCA RECOMMENDED
(June 30, 2004)

	AMOUNT ($000)	PCT	COST	WEIGHTED COST
LONG- TERM DEBT	$2,085,152	46.89%	6.56%	3.08%
SHORT-TERM DEBT	$167,960	3.78%	1.0823%	0.04%
PREFERRED STOCK	$115,586	2.60%	6.40%	0.17%
COMMON STOCK	$2,078,192	46.73%	9.60%	4.49%
TOTAL	$4,446,890	100.00%		7.77%

SCE&G RETAIL ELECTRIC
CAPITAL STRUCTURE & COST OF CAPITAL
(EXCLUDING S-T DEBT and USING ALTERNATIVE DCF ANALYSIS)

	AMOUNT ($000)	PCT	COST	WEIGHTED COST
LONG- TERM DEBT	$2,085,152	48.73%	6.56%	3.20%
PREFERRED STOCK	$115,586	2.70%	6.40%	0.17%
COMMON STOCK	$2,078,192	48.57%	9.10%	4.42%
TOTAL	$4,278,930	100.00%		7.79%

Exhibit___(GAW-1)
Schedule 7

DAILY CLOSING STOCK PRICES
(9/17/02 - 12/18/02)

Date	SCANA	S&P 500	PUBLIC UTILITY INDEX
18-Dec-02	$30.65	$891.12	$256.14
17-Dec-02	$30.72	$902.99	$256.32
16-Dec-02	$30.83	$910.40	$254.31
13-Dec-02	$30.75	$889.48	$251.52
12-Dec-02	$30.45	$901.58	$249.41
11-Dec-02	$30.18	$904.96	$248.31
10-Dec-02	$30.10	$904.45	$246.06
09-Dec-02	$29.84	$892.00	$243.47
06-Dec-02	$29.90	$912.23	$241.29
05-Dec-02	$30.36	$906.55	$240.69
04-Dec-02	$30.36	$917.57	$241.94
03-Dec-02	$30.61	$920.75	$247.85
02-Dec-02	$30.31	$934.53	$242.39
29-Nov-02	$30.09	$936.31	$245.76
27-Nov-02	$30.09	$938.87	$245.74
26-Nov-02	$29.91	$913.31	$244.07
25-Nov-02	$30.35	$932.87	$249.74
22-Nov-02	$29.92	$930.55	$248.75
21-Nov-02	$29.65	$933.76	$241.25
20-Nov-02	$29.48	$914.15	$239.82
19-Nov-02	$29.59	$896.74	$238.86
18-Nov-02	$29.42	$900.36	$239.09
15-Nov-02	$29.56	$909.83	$240.96
14-Nov-02	$28.97	$904.27	$236.28
13-Nov-02	$28.47	$882.53	$233.24
12-Nov-02	$27.98	$882.95	$231.09
11-Nov-02	$28.69	$876.18	$236.37
08-Nov-02	$28.86	$894.74	$239.13
07-Nov-02	$29.28	$902.65	$246.18
06-Nov-02	$29.86	$923.76	$256.58
05-Nov-02	$29.68	$915.39	$254.08
04-Nov-02	$29.47	$908.34	$254.41
01-Nov-02	$29.26	$900.96	$246.84
31-Oct-02	$29.18	$885.77	$245.40
30-Oct-02	$29.02	$890.71	$246.76
29-Oct-02	$28.95	$882.15	$241.76
28-Oct-02	$29.20	$890.23	$242.81
25-Oct-02	$28.84	$897.65	$238.54
24-Oct-02	$28.35	$882.50	$234.42
23-Oct-02	$28.21	$896.14	$235.03
22-Oct-02	$27.72	$890.16	$229.00
21-Oct-02	$27.86	$899.72	$233.68
18-Oct-02	$27.10	$884.39	$221.13
17-Oct-02	$27.02	$879.20	$219.08
16-Oct-02	$26.15	$860.02	$213.93
15-Oct-02	$27.05	$881.27	$222.82
14-Oct-02	$27.29	$841.44	$222.69
11-Oct-02	$27.42	$835.32	$225.59
10-Oct-02	$27.62	$803.92	$224.11
09-Oct-02	$25.32	$776.76	$206.34
08-Oct-02	$25.50	$798.55	$227.10
07-Oct-02	$25.39	$785.28	$238.29
04-Oct-02	$25.55	$800.58	$238.94
03-Oct-02	$25.63	$818.95	$248.86
02-Oct-02	$25.66	$827.91	$252.91
01-Oct-02	$26.62	$847.91	$257.37
30-Sep-02	$26.02	$815.29	$252.23
27-Sep-02	$25.91	$827.37	$249.73
26-Sep-02	$26.38	$854.95	$253.91
25-Sep-02	$25.79	$839.66	$244.56
24-Sep-02	$25.20	$819.29	$239.88
23-Sep-02	$25.40	$833.70	$245.23
20-Sep-02	$25.44	$845.39	$249.53
19-Sep-02	$25.98	$843.32	$253.31
18-Sep-02	$26.18	$869.46	$257.81
17-Sep-02	$25.36	$873.52	$249.82

Source: Yahoo Finance daily prices.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Net Operating Income and Rate of Return
Test Year Ended March 2004
SCE&G vs. SCCA PROPOSED
($000)

	SCE&G 1/			SCCA 2/		
	ADJUSTED @ CURRENT RATES	PROPOSED	INCREASE	ADJUSTED @ CURRENT RATES	PROPOSED	INCREASE
OPERATING INCOME:						
Total Operating Revenues	$1,478,654	$1,559,846	$81,192	$1,479,585	$1,440,460	($39,125)
Total Operating Expenses	$1,203,024	$1,227,586	$24,562	$1,176,537	$1,161,465	($15,072)
Net Operating Income	$275,630	$332,260	$56,630	$303,048	$278,994	($24,054)
Interest on Customers' Deposits	($805)	($805)	$0	($805)	($805)	$0
Customer Growth	$2,975	$3,586	$611	$3,271	$3,011	($260)
Net Operating Income for Return	**$277,800**	**$335,041**	**$57,241**	**$305,514**	**$281,200**	**($24,313)**
RATE BASE:						
Plant in Service	$5,739,630	$5,739,630	- -	$5,738,373	$5,738,373	- -
Accum. Depreciation	($1,792,817)	($1,792,817)	- -	($1,792,771)	($1,792,771)	- -
Net Plant	$3,946,813	$3,946,813	- -	$3,945,601	$3,945,601	- -
CWIP	$123,201	$123,201	- -	$123,201	$123,201	- -
Deferred Debits/Credits	($84,966)	($84,966)	- -	($91,518)	($91,518)	- -
Working Capital	$2,089	$2,089	- -	($1,942)	($1,942)	- -
Materials & Supplies	$139,666	$139,666	- -	$120,825	$120,825	- -
Accum. Deferred Income Taxes	($477,114)	($477,114)	- -	($477,114)	($477,114)	- -
Total Rate Base	**$3,649,689**	**$3,649,689**	**- -**	**$3,619,054**	**$3,619,054**	**- -**
RATE OF RETURN ON RATE BASE	7.61%	9.18%	**- -**	8.44%	7.77%	**- -**

1/ Per SCE&G Exhibit D-II, Page 2.
2/ Per Page 2.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTED
($000)

	(1) TOTAL ELECTRIC PER BOOKS 1/	(2) ALLOCATED RETAIL PER BOOKS 1/	SCE&G PROFORMA RETAIL ADJUSTMENTS	(3) SCE&G PROFORMA RETAIL 2/	(4) SCCA ADJUSTMENTS TO SCE&G PROFORMA RETAIL 3/	(5) ADJUSTED RETAIL @ CURRENT RATES (3) + (4)	(6) REQUIRED INCREASE	(7) RETAIL AFTER INCREASE (5) + (6)
OPERATING REVENUES	$1,515,375	$1,450,375	$28,279	$1,478,654	$931	$1,479,585	($39,125)	$1,440,460
OPERATING EXPENSES								
O&M EXPENSES-FUEL	$402,795	$374,926	$49	$374,975	$0	$374,975		$374,975
O&M EXPENSES-OTHER	$400,580	$383,340	$43,904	$427,244	($32,248)	$394,996		$394,996
DEPRECIATION & AMORTIZATION	$173,315	$166,320	$37,573	$203,893	($46)	$203,847		$203,847
TAXES OTHER THAN INCOME	$112,376	$108,036	$10,916	$118,952	($422)	$118,530	($172)	$118,358
STATE INCOME TAXES	$8,671	$8,605	($3,002)	$5,603	$887	$6,490	($1,948)	$4,542
FEDERAL INCOME TAXES	$53,680	$54,114	($19,768)	$34,346	$5,341	$39,687	($12,952)	$26,735
DEFERRED TAX EXPENSE	$39,336	$38,006	($14)	$37,992	$0	$37,992		$37,992
ITC EXPENSE	$20	$19	$0	$19	$0	$19		$19
TOTAL OPERATING EXPENSES	$1,190,773	$1,133,366	$69,658	$1,203,024	($26,487)	$1,176,537	($15,072)	$1,161,465
OPERATING RETURN	$324,602	$317,009	($41,379)	$275,630	$27,418	$303,048	($24,054)	$278,994
CUSTOMER GROWTH	$3,424	$3,424	($449)	$2,975	$296	$3,271	($260)	$3,011
INTEREST ON CUSTOMER DEPOSITS	($805)	($805)	$0	($805)	$0	($805)		($805)
NET RETURN	$327,221	$319,628		$277,800	$27,714	$305,514	($24,313)	$281,200
RATE BASE								
PLANT IN SERVICE	$5,425,328	$5,207,147	$532,483	$5,739,630	($1,257)	$5,738,373		$5,738,373
DEPRECIATION RESERVE	($1,846,528)	($1,772,888)	($19,929)	($1,792,817)	$46	($1,792,771)		($1,792,771)
NET PLANT IN SERVICE	$3,578,800	$3,434,259	$512,554	$3,946,813	($1,212)	$3,945,601		$3,945,601
Add:								
CONSTRUCTION WORK IN PROGRESS	$900,653	$849,669	($726,468)	$123,201	$0	$123,201		$123,201
MATERIALS & SUPPLIES	$125,178	$117,947	$21,719	$139,666	($18,841)	$120,825		$120,825
CASH WORKING CAPITAL	$83,777	$79,235	$4,428	$83,663	($4,031)	$79,632		$79,632
PREPAYMENTS	$14,569	$14,111	$0	$14,111	$0	$14,111		$14,111
DEF DEBIT/ ENVIRONMENTAL	($136)	($131)	$1	($130)	$0	($130)		($130)
GridSouth COSTS	$0	$0	$6,552	$6,552	($6,552)	$0		$0
Deduct:								
ACCUMULATED DEFERRED INCOME TAXES	($496,781)	($477,215)	$101	($477,114)	$0	($477,114)		($477,114)
AVERAGE TAX ACCRUALS	($72,404)	($70,758)	$145	($70,613)	$0	($70,613)		($70,613)
CUSTOMER DEPOSITS	($19,882)	($19,882)	$0	($19,882)	$0	($19,882)		($19,882)
INJURIES & DAMAGES	($5,407)	($5,190)	$0	($5,190)	$0	($5,190)		($5,190)
OPEBS	($72,735)	($69,846)	($796)	($70,642)	$0	($70,642)		($70,642)
STORM RESERVE	($20,746)	($20,746)	$0	($20,746)	$0	($20,746)		($20,746)
TOTAL RATE BASE	$4,014,886	$3,831,453	($181,764)	$3,649,689	($30,635)	$3,619,054		$3,619,054
RATE OF RETURN ON RATE BASE	8.15%	8.34%		7.61%		8.44%		7.77%

1/ Per SCE&G response to Staff #1-33 (Per Books Study).
2/ Per SCE&G response to Staff #1-33 (Proforma Study).
3/ Per Schedule 2.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNTS
OPERATING INCOME
($000)

	ADJUSTMENT	REVENUES	O&M EXPENSES	DEPREC. & AMORT. EXPENSE	TAXES OTHER THAN INCOME	STATE INCOME TAX	FEDERAL INCOME TAX
1	Annualize NCEMC Contracts	$931 1/				$47	$309
2	Amortize Purchased Power Settlement		($3,179) 2/			$159	$1,057
3	Eliminate S-T Capacity Purchases					$0	$0
4	Williams Station Environ. Costs					$0	$0
5	Future Turbine Investment & O&M		($5,038) 3/			$252	$1,675
6	Ammonia Costs		$17 4/			($1)	($6)
7	Compensation		($5,513) 5/		($422) 5/	$297	$1,973
8	Pensions & Health Care					$0	$0
	(a) Pensions					$0	$0
	(b) OPEBs					$0	$0
	(c) Health Care		($508) 6/			$25	$169
9	Long Term Disability					$0	$0
10	DSM Costs					$0	$0
11	Employee Clubs					$0	$0
12	Property Retirements					$0	$0
	(a) Plant in Service					$0	$0
	(b) Depreciation Reserve					$0	$0
13	Property Additions					$0	$0
	(a) Other Plant in Service					$0	$0
	(b) Deprec. Reserve Adj. for Retirements					$0	$0
	(c) Transmission Plant Additions		($988) 7/	($46) 7/		$52	$344
14	Annualize Current Deprec. Rates					$0	$0
15	New Deprec. Study					$0	$0
16	Property Taxes					$0	$0
17	Jasper Project		($14,398) 8/			$720	$4,787
18	Saluda Dam Project					$0	$0
19	Fossil Fuel Inventory					$0	$0
20	GridSouth		($2,641) 9/			$132	$878
21	Cash Working Capital					$0	$0
22	Interest Syncronization					($795) 10/	($5,846) 10/
						$0	$0
	TOTAL	$931	($32,248)	($46)	($422)	$887	$5,341

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNTS
RATE BASE
($000)

	ADJUSTMENT	PLANT IN SERVICE	DEPR. RESERVE	CWIP	MAT. & SUPP.	WORKING CAPITAL	DEFERRED OPEB	DEFERRED GRIDSOUTH
1	Annualize NCEMC Contracts							
2	Amortize Purchased Power Settlement							
3	Eliminate S-T Capacity Purchases							
4	Williams Station Environ. Costs							
5	Future Turbine Investment & O&M							
6	Ammonia Costs							
7	Compensation							
8	Pensions & Health Care							
	(a) Pensions							
	(b) OPEBs							
	(c) Health Care							
9	Long Term Disability							
10	DSM Costs							
11	Employee Clubs							
12	Property Retirements							
	(a) Plant in Service							
	(b) Depreciation Reserve							
13	Property Additions							
	(a) Other Plant in Service							
	(b) Deprec. Reserve Adj. for Retirements							
	(c) Transmission Plant Additions	($1,257) 7/	$46 7/					
14	Annualize Current Deprec. Rates							
15	New Deprec. Study							
16	Property Taxes							
17	Jasper Project							
18	Saluda Dam Project							
19	Fossil Fuel Inventory				($18,841) 11/			
20	GridSouth							($6,552) 9/
21	Cash Working Capital					($4,031) 12/		
22	Interest Syncronization							
		($1,257)	$46	$0	($18,841)	($4,031)	$0	($6,552)

1/PER SCHEDULE 10.
2/PER SCHEDULE 11.
3/PER SCHEDULE 12.
4/PER SCHEDULE 13.
5/PER SCHEDULE 14.
6/PER SCHEDULE 15.
7/PER SCHEDULE 16.
8/PER SCHEDULE 17.
9/PER SCHEDULE 19.
10/PER SCHEDULE 21.
11/PER SCHEDULE 18.
12/PER SCHEDULE 20.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
ANNUALIZE NCEMC CONTRACTS
(Adjustment #1)

ENERGY MARGIN:	**250 MW CONTRACT**	**100 MW CONTRACT**	**TOTAL**
ACTUAL BOOKED IN TEST YEAR (Jan - Mar) 1/	$1,047,601	$2,546,427	$3,594,028
ACTUAL AFTER TEST YEAR (Apr - Jun) 2/	($428,912)	$890,076	$461,164
TOTAL ACTUAL (Jan - Jun)	$618,689	$3,436,503	$4,055,192
MONTHS	6	6	6
AVG ENERGY MARGIN / MTH	$103,115	$572,751	$675,865
ESTIMATE JUL - DEC	$618,689	$3,436,503	$4,055,192
ADJ TO TEST YEAR (Apr - Dec)	$189,777	$4,326,579	$4,516,356
SCE&G ADJUSTMENT (Apr - Jun) 1/	($737,033)	$4,253,682	$3,516,649
SCCA ADJ TO SCE&G (Total Elect.)	$926,810	$72,897	$999,707
PERCENT RETAIL 1/	93.09%	93.09%	93.09%
SCCA ADJ TO SCE&G (Retail)	$862,767	$67,860	$930,627
($000)			$931

1/ Per Staff #1-62.
2/ Per Consumer Advocate # 1-39.

Exhibit__(GAW-1)
Schedule 11

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
AMORTIZE PURCHASED POWER SETTLEMENT
(Adjustment # 2)

TOTAL SETTLEMENT AMOUNT 1/	$25,618,063
AMORTIZATION PERIOD	5
ANNUAL EXPENSE	$5,123,613
SCE&G ADJUSTMENT 1/	$8,539,354
SCCA ADJ TO SCE&G (Total Elect.)	($3,415,741)
PERCENT RETAIL 1/	93.08%
SCCA ADJ TO SCE&G (Retail)	($3,179,372)
($000)	($3,179)

1/ Per Staff #1-62.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
AMORTIZE FUTURE EXPENSE AND INVESTMENT
(Adjustment # 5)

SCE&G ADJUSTMENT (Total Elect.)	$5,412,193
SCE&G ADJUSTMENT (Retail)	$5,038,180
REVERSE ADUSTMENT	($5,038,180)
($000)	($5,038)

Exhibit__(GAW-1)
Schedule 13

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
SELECTIVE CATALYTIC REACTOR AMMONIA COSTS
(Adjustment # 6)

	WILLIAMS GENERATION UNIT	WATEREE GENERATION UNIT	TOTAL
AMMONIA TONS@ 100% CAP. FACTOR	2,160	2,426	
OZONE SEASON CAPACITY FACTOR	90%	90%	
ESTIMATED TONS	1,944	2,183	
CURRENT AMMONIA PRICE/ TON (6/04)	$267.50	$267.50	
SUPPLIER MARGIN	$102.00	$110.00	
TOTAL COST / TON	$369.50	$377.50	
ESTIMATED COST	$718,308	$824,234	$1,542,542
SCE&G ADJUSTMENT	$709,560	$814,408	$1,523,968
SCCA ADJ TO SCE&G (Total Elect.)	$8,748	$9,826	$18,574
PERCENT RETAIL	93.08%	94.10%	
SCCA ADJ TO SCE&G (Retail)	$8,143	$9,246	$17,388
($000)			$17

Sources: Staff #1-62 and Staff Audit Request #19.

Exhibit__(GAW-1)
Schedule 14

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
WAGES, BENEFITS and PAYROLL TAXES
(Adjustment # 7)

PAYROLL:		
	OFFICER CASH INCENTIVE COMPENSATION (ELECT.)	$6,549,083
	EMPLOYEE INCENTIVE COMPENSATION (ELECT.)	$4,938,540
	TOTAL	$11,487,623
	50% / 50% SHARING RATEPAYERS AND SHAREHOLDERS	50%
	SCCA ADJUSTMENT TO SCE&G AMOUNT (TOTAL ELECT.)	($5,743,812)
	PERCENT RETAIL	95.98%
	SCCA ADJUSTMENT TO SCE&G AMOUNT (RETAIL)	($5,512,910)
	($000)	($5,513)
PAYROLL TAXES:		
	SCCA RETAIL PAYROLL ADJUSTMENT	($5,512,910)
	TAX PERCENTAGE IN SCE&G ADJUSTMENT	7.65%
	SCCA RETAIL PAYROLL TAX ADJUSTMENT	($421,738)
	($000)	($422)

Sources: Staff #'s 1-62, 1-77,1-89, and 1-50.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
HEALTH CARE
(Adjustment # 8c)

MEDICAL CARE ANNUAL INFLATION (1ST Half 2003 TO 1ST Half 2004): 1/	
CPI MEDICAL CARE - SOUTHERN U.S. (ALL URBAN CONSUMERS)	3.9%
CPI MEDICAL CARE - SOUTHERN U.S. (METRO SIZE 50,000 - 1,500,000)	4.1%
CPI MEDICAL CARE - SOUTHERN U.S. (METRO SIZE < 50,000)	3.2%
SELECTED	4.1%
TEST YEAR HEALTH CARE COSTS (TOTAL SCE&G) 2/	$27,832,606
INCREASE TO HEALTH CARE COSTS (TOTAL SCE&G)	$1,141,137
SCE&G ELECT. O&M PERCENTAGE 2/	44.81%
INCREASE TO HEALTH CARE COSTS (TOTAL ELECT)	$511,343
SCE&G ADJUSTMENT (TOTAL ELECT.)2/	$1,043,702
SCCA ADJ TO SCE&G (Total Elect.)	($532,359)
PERCENT RETAIL 2/	95.35%
SCCA ADJ TO SCE&G (Retail)	($507,604)
($000)	($508)

1/ Per U.S. Deprtment of Labor, Bureau of Labor Statistics (detailed CPI components for Southern U.S.).
2/ Per Staff #1-62.

Exhibit__(GAW-1)
Schedule 16

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
FUTURE NERC INVESTMENT & EXPENSES
(Adjustment # 13c)

GENERAL PLANT:		
	SCE&G ADJUSTMENT (RETAIL)	$1,257,270
	REVERSE ADJUSTMENT	($1,257,270)
	($000)	($1,257)
ACCUMULATED DEPRECIATION:		
	SCE&G ADJUSTMENT (RETAIL)	($45,750)
	REVERSE ADJUSTMENT	$45,750
	($000)	$46
O&M EXPENSE:		
	SCE&G ADJUSTMENT (RETAIL)	$988,235
	REVERSE ADJUSTMENT	($988,235)
	($000)	($988)
DEPRECIATION EXPENSE:		
	SCE&G ADJUSTMENT (RETAIL)	$45,750
	REVERSE ADJUSTMENT	($45,750)
	($000)	($46)

Exhibit__(GAW-1)
Schedule 17

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
JASPER ADJUSTMENTS
(Adjustment # 17)

FIRM GAS CAPACITY FUEL COSTS:	
SCE&G ADJUSTMENT (RETAIL)	$14,397,547
REVERSE ADJUSTMENT	($14,397,547)
($000)	($14,398)

Exhibit__(GAW-1)
Schedule 18

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
FOSSIL FUEL INVENTORY ADJUSTMENT
(Adjustment # 19)

COAL INVENTORY:

MONTH	TONS 1/
APR 03	715,226
MAY 03	684,427
JUN 03	634,350
JUL 03	477,087
AUG 03	472,510
SEP 03	502,433
OCT 03	590,053
NOV 03	599,239
DEC 03	549,428
JAN 04	378,839
FEB 04	338,342
MAR 04	347,321
AVERAGE	524,105
PRICE/ TON (6/30/04) 2/	$47.48

COAL VALUE	$24,884,887
OTHER FUEL: 1/	$5,158,142
TOTAL AVG. FOSSIL FUEL INVENTORY	$30,043,029
AVERAGE TY INVENTORY PER BOOKS 1/	$26,944,786
FOSSIL FUEL INVENTORY ADJUSTMENT (TOTAL ELECT.)	$3,098,243
SCE&G ADJUSTMENT (TOTAL ELECT.) 1/	$23,339,940
SCCA ADJUSTMENT TO SCE&G AMOUNT (TOTAL ELECT.)	($20,241,697)
PCT RETAIL 1/	93.08%
SCCA ADJUSTMENT TO SCE&G (RETAIL)	($18,840,972)
($000)	($18,841)

1/ Per Staff #1-62 and Staff Audit Request #41.
2/ per Columbia Energy #1-27.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
GridSouth
(Adjustment # 20)

AMORTIZATION OF GridSouth COSTS:	
SCE&G ADJUSTMENT (RETAIL)	$2,641,181
REVERSE ADJUSTMENT	($2,641,181)
($000)	($2,641)

UNAMORTIZED BALANCE OF GridSouth COSTS:	
SCE&G ADJUSTMENT (RETAIL)	$6,551,983
REVERSE ADJUSTMENT	($6,551,983)
($000)	($6,552)

Exhibit__(GAW-1)
Schedule 20

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
CASH WORKING CAPITAL ADJUSTMENT (Adjustment #21)
($000)

Adjustments to SCE&G PROFORMA O&M Expenses	($32,248)
Less Retail X518 and X555 Adjustments	$0
Subtotal	($32,248)
1/8 of Retail O&M Adustments	($4,031)

Exhibit__(GAW-1)
Schedule 21

SOUTH CAROLINA ELECTRIC & GAS COMPANY
SOUTH CAROLINA RETAIL
Docket No. 2004-178-E
Test Year Ended March 2004
SCCA ADJUSTMENTS TO SCE&G PROFORMA AMOUNT
INTEREST SYNCHRONIZATION ADJUSTMENT (Adjustment #22)
($000)

	RETAIL ELECTRIC
PER BOOKS ADJUSTMENT:	
PER BOOKS RATE BASE	$3,831,455
WEIGHTED COST OF DEBT 1/	3.1169%
INTEREST EXPENSE	$119,421
LESS PER BOOKS INTEREST	$102,559
PER BOOKS INTEREST ADJUSTMENT	$16,862
SCCA ADJUSTMENTS TO SCE&G PROFORMA	
PLANT IN SERVICE	(1,257)
REDUCTION IN ACCUM. DEPRECIATION	46
CWIP	0
MATERIALS & SUPPLIES	(18,841)
DEFERRED DEBITS AND CREDITS	(6,552)
CASH WORKING CAPITAL	(4,031)
TOTAL	(30,635)
WEIGHTED COST OF DEBT 1/	3.1169%
INTEREST ADJUSTMENT	($955)
TOTAL RETAIL INCRASE TO SCE&G PROFORMA INTEREST	$15,908
RETAIL STATE INCOME TAX EFFECT	($795)
RETAIL FEDERAL INCOME TAX EFFECT	($5,846)

1/ Per Schedule 5.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
Docket No. 2004-178-E
Test Year Ended March 2004
SCE&G OVERSTATEMENT OF INCOME TAXES
($000)

	TOTAL ELECTRIC				RETAIL ELECTRIC			
	SCE&G PER BOOKS 1/	INTEREST SYNCH. ADJ. 2/	ADJUSTED PER BOOKS	REQUIRED ADJ. BEFORE OTHER PROFORMA ADJUSTMENTS	SCE&G PER BOOKS 1/	INTEREST SYNCH. ADJ. 3/	ADJUSTED PER BOOKS	REQUIRED ADJ. BEFORE OTHER PROFORMA ADJUSTMENTS
STATE INCOME TAXES:								
OPERATING INCOME BEFORE TAX	$426,309		$426,309		$417,752		$417,752	
OTHER TAXABLE DEDUCTIONS:								
CAPITALIZED & USE TAX	($3,225)		($3,225)		($3,095)		($3,095)	
INTEREST	$107,423	$15,126	$122,549		$102,559	$14,391	$116,950	
ACCEL. DEPR. (OVER BOOK)	$42,808		$42,808		$41,080		$41,080	
NUC. FUEL EXPENSE	($20,569)		($20,569)		($19,146)		($19,146)	
COST OF REMOVAL & PROP TAX	$15,106		$15,106		$14,222		$14,222	
EMPLOYEE BENEFITS	($883)		($883)		($848)		($848)	
UNBILLED REV.	$13,358		$13,358		$12,821		$12,821	
ROTO SHOT	($7,830)		($7,830)		($7,830)		($7,830)	
TOTAL OTHER DEDUCTIONS	$146,188		$161,314		$139,763		$154,154	
STATE TAXABLE INCOME	$280,121		$264,995		$277,989		$263,598	
SIT @ 5%	$14,006		$13,250		$13,899		$13,180	
SIT PRIOR YR ADJUSTMENTS	($5,335)		($5,335)		($5,294)		($5,294)	
TOTAL STATE INCOME TAX	$8,671		$7,915	($756)	$8,605		$7,886	($720)
FEDERAL INCOME TAXES:								
OPERATING INCOME BEFORE TAX	$426,309		$426,309		$417,752		$417,752	
OTHER TAXABLE DEDUCTIONS:								
CAPITALIZED & USE TAX	($3,225)		($3,225)		($3,095)		($3,095)	
INTEREST	$107,423	$15,126	$122,549		$102,559	$14,391	$116,950	
ACCEL. DEPR. (OVER BOOK)	$128,985		$128,985		$123,779		$123,779	
NUC. FUEL EXPENSE	($20,569)		($20,569)		($19,146)		($19,146)	
COST OF REMOVAL & PROP TAX	$15,106		$15,106		$14,222		$14,222	
EMPLOYEE BENEFITS	($883)		($883)		($848)		($848)	
UNBILLED REV.	$13,358		$13,358		$12,821		$12,821	
ROTO SHOT	($7,830)		($7,830)		($7,830)		($7,830)	
STATE INCOME TAXES	$14,006		$14,006		$13,899		$13,899	
TOTAL OTHER DEDUCTIONS	$246,371		$261,497		$236,361		$250,753	
FEDERAL TAXABLE INCOME	$179,938		$164,812		$181,391		$166,999	
FIT @ 35%	$62,978		$57,684		$63,487		$58,450	
FIT PRIOR YR ADJUSTMENTS	($9,298)		($9,298)		($9,373)		($9,373)	
TOTAL FEDERAL INCOME TAX	$53,680		$48,386	($5,294)	$54,114		$49,077	($5,037)
TOTAL INCOME TAXES	$62,351		$56,301	($6,050)	$62,719		$56,963	($5,756)

1/ Per response to Staff # 1-33.

2/	PER BOOKS RATE BASE(TOTAL ELECT)	$4,014,886
	WEIGHTED COST OF DEBT	3.0524%
	ADJUSTED INTEREST (TOTAL ELECT.)	$122,549
	PER BOOKS INTEREST (TOTAL ELECT)	$107,423
	INTEREST SYNC. (TOTAL ELECT.)	$15,126
3/	PER BOOKS RATE BASE(RETAIL):	$3,831,455
	WEIGHTED COST OF DEBT	3.0524%
	ADJUSTED INTEREST (RETAIL)	$116,950
	PER BOOKS INTEREST (RETAIL)	$102,559
	INTEREST SYNC. (RETAIL.)	$14,391